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September 4, 2008

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. - Fort Nelson Service Area (TG Fort Nelson)

2009 Revenue Requirements Application for Changes to the Revenue Stabilization Adjustment Mechanism ("RSAM") Rate Rider and Delivery Rates effective January 1, 2009

Pursuant to Sections 58, 60 and 61 of the *Utilities Commission Act* (the "Act"), attached please find the TG Fort Nelson application for approval of its 2009 Revenue Requirements and changes to the RSAM rate rider and delivery rates effective January 1, 2009 (the "Application") on a permanent basis.

If you have any questions related to this filing, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachments

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SECTION 1 - INTRODUCTION AND EXECUTIVE SUMMARY

1.1 Purpose of Application

Terasen Gas Inc. ("Terasen Gas" or the "Company") is seeking an increase in its rates for delivery service to customers on the natural gas distribution system in the Fort Nelson Service Area ("TG Fort Nelson") to reflect increases in its revenue requirements of 3.5 percent of total revenues, effective January 1, 2009 (the "2009 Revenue Requirements and Rates Application" or the "Application"). This increase is required to ensure that the Company's rates recover the costs of serving its customers. The rate increases, proposed in this Application for which approval is sought, represent an increase of approximately 3% on a total bill basis for residential and commercial customers (customers served under Rate Schedules 1, 2.1, and 2.2). The proposed increase for the customer served under Rate Schedule 25 is an increase of approximately 17%, equal to the proposed increase in the delivery margin (refer to Section 10, Schedule 1.1).

This 2009 Revenue Requirements and Rates Application includes a detailed discussion of the components influencing the need for a revenue requirement increase for 2009. In support of the Application, Terasen Gas has provided discussion of the business drivers, capital expenditures and operating and maintenance requirements of TG Fort Nelson for 2009. Terasen Gas has maintained a high standard of providing safe, reliable and efficient service to TG Fort Nelson customers during its term of ownership.

1.2 Major Issues

The forest industry in the province of British Columbia has undergone significant challenges over the past number of years which are expected to continue in the future. Several companies have announced reductions in their production levels or, as in some cases the full closure of facilities.

During the regulatory review process of the 2008 Revenue Requirements and Rates Application, on January 18, 2008, Canadian Forest Products Ltd. ("Canfor"), announced the closure of its two facilities served under Rate Schedule 25 operating in Fort Nelson (PolarBoard Oriented Strand Board ("OSB") Plant and Tackama Plywood Mill).

Subsequently, on February 25, 2008, after receiving concessions from the union representing mill workers, suppliers and the provincial government, Canfor announced it would be able to keep the Tackama Mill open. The lone remaining industrial customer using natural gas in Fort Nelson, the Tackama Mill, accounts for approximately 28% of TG Fort Nelson's forecast natural gas demand in 2009. In contrast, in 2006 before the turndown in the forestry sector and when the PolarBoard Plant was operating, total industrial demand was approximately 36% of the total demand in the TG Fort Nelson region. Closure of forestry plants and mills in smaller communities like Fort Nelson has a material and significant impact on delivery margin requirements.

The decline in residential use rates experienced over the last several years throughout the province is also evident in Fort Nelson. Declining use rates have a significant impact on the energy forecast, which is a factor for both use rates and the number of customer additions in the region.

Considering these major issues, the Company believes that it has made reasonable estimates of use rates and customer additions for the year 2009. TG Fort Nelson has always worked to mitigate the impact to customer rates and believes that future consideration of consolidation of the Fort Nelson Service area with the remainder of Terasen Gas for regulatory purposes could mitigate the wide variability in rates that can occur in Fort Nelson due to it's relatively small service area and the industry-dependent economic challenges it faces.

1.3 Organization of Application

Section 1 Introduction and Executive Summary

Section 2 History and Overview – discusses Terasen Gas and TG Fort Nelson background including operations, gas supply arrangements and historical revenue requirement changes.

Section 3 Demand and Revenue Forecast – discusses the impact of use rates, customer additions and other factors affecting demand, revenue and margin in the Fort Nelson region.

Section 4 Cost of Gas – discusses the impact of gas costs on total revenue requirement changes.

Section 5 Operating and Maintenance ("O&M") Expenses

Section 6 Taxes, Deferred Charges, Amortization and Depreciation Expenses

Section 7 Capital Requirements and Rate Base

Section 8 Financing and Capital Structure

Section 9 Revenue Requirements and Rates – discusses
- Customers bill impacts
- Fort Nelson rates comparison to other utilities

Section 10 Financial Schedules

1.4 Relief Sought

The requirement for an increase in revenues is determined by various business drivers including projected customer use rates, volumes and revenues, capital expenditures and operating and maintenance expenses of TG Fort Nelson. Detailed support material has been provided in Sections 3 through 9 which shows the impact of these business drivers on the TG Fort Nelson revenue requirements for 2009. Overall, TG Fort Nelson has experienced a decrease in delivery margin due to declining industrial demand, customer use rates and an increase in the cost of service (excluding cost of gas), which has resulted in a revenue deficiency for 2009.

As shown in Table 1.4 below, approximately 70% ($146,000) of total revenue deficiency of $209,000 is primarily due to decline in use rates per customer and industrial demand. The decline in industrial demand for customers served by Rate Schedule 25 ("Industrial Customers") is caused by the closure of Canfor's PolarBoard Plant, which accounts for approximately 27% ($57,000) of the total revenue deficiency for 2009. Declining use per customer rates, after offsetting customer additions, for customers served under Rate Schedules 1, 2.1, and 2.2 ("Core Customers") accounts for approximately 26% ($55,000) of the revenue deficiency. The remaining 30% ($63,000) of the total revenue deficiency is due to an increase in the cost of service, which includes expenses related to operations and maintenance, property tax, depreciation, amortization, interest and income tax.

A summary of revenue deficiency has been provided in Table 1.4 below.

Table 1.4 – TG Fort Nelson Revenue Deficiency Details

Description	2008 Decision	2009 Forecast @ Existing Rates	Difference
Revenue			
Residential/Commercial	5,134	5,707	573
Transportation Service	295	231	(64)
Total Revenue:	**5,429**	**5,938**	**509**
Less:			
Cost of Gas	4,054	4,709	655
Gross Margin:	**1,375**	**1,229**	**(146)**
Cost of Service (excl. COG)			
O&M	652	664	12
Property Tax	125	158	33
Depreciation	170	188	18
Amortization	28	6	(22)
Income Tax	49	61	12
Interest Expense	233	243	10
Other Revenue	(38)	(45)	(7)
Return on Equity	156	164	8
Total Cost of Service:	**1,375**	**1,438**	**63**
Deficiency:	**0**	**(209)**	**(209)**

TG Fort Nelson hereby respectfully requests approval from the British Columbia Utilities Commission (the "Commission"), pursuant to Sections 58, 60 and 61 of the *Utilities Commission Act*, for the following:

- To allow TG Fort Nelson to recover the revenue deficiency of $209,000 through a permanent increase in its delivery rates, effective January 1, 2009.
- A margin increase of 17% and revised rates as per Section 10, Schedule 1.1 and Tables 9a and 9b, effective January 1, 2009.
- The RSAM rider to be set to $0.143 (an increase of $0.027) as per Table 3.7, effective January 1, 2009.
- Rates to be revised to reflect the Commission approved allowed Return on Equity ("ROE") as per the Generic Mechanism, expected in early December 2008.

Should the Commission be unable to render its decision on the TG Fort Nelson 2009 Revenue Requirements Application for permanent rates in time to be effective January 1, 2009, TG Fort Nelson hereby requests approval pursuant to Section 89 of the *Utilities Commission Act* of the same rates on an interim basis, effective January 1, 2009.

1.5 Customer Impacts

The requested rate increase, exclusive of the RSAM rider, will increase the residential rate by $0.306 per GJ on average. The annual effect of this increase is approximately $43 per residential customer at the average forecast annual consumption of 140 GJ. This relates to about 3% increase in the total average annual bill of approximately $1,435 for residential customers. For commercial customers (customers served by Rate Schedules 2.1 and 2.2), the rate increase will be approximately $0.309 per GJ on average. While the consumption levels of commercial customers vary quite widely, using the average annual forecast consumption of 686 GJ per customer, the annual increase for a commercial customer will be approximately $210, an increase of approximately 3% in the total average annual bill of approximately $7,050. For industrial customers (customers served by Rate Schedule 25), the requested rate increase will increase the industrial rate by 0.166 per GJ on average, an increase of approximately 17%.

1.6 Proposed Regulatory Process

The Company is of the view that a written hearing process is appropriate for the review of this Application, and proposes the following regulatory timetable:

Thursday, September 4, 2008	TG Fort Nelson Application submitted
Thursday, September 11, 2008	Commission Issues Procedural Order
Thursday, September 18, 2008	Commission Information Request No. 1 to TG Fort Nelson
Thursday, September 25, 2008	Intervenor Registration and Comments regarding Regulatory Review Process
Thursday, October 2, 2008	Commission confirms Regulatory Timetable and Intervenors Information Request No. 1 to TG Fort Nelson
Thursday, October 16, 2008	TG Fort Nelson Response to Commission and Intervenor Information Request No. 1

Thursday, October 30, 2008	Commission and Intervenors Information Request No. 2 to Terasen Gas (if necessary)
Thursday, November 6, 2008	TG Fort Nelson Responds to Commission and Intervenor Information Request No. 2
Thursday, November 13, 2008	Intervenors Comments
Thursday, November 20, 2008	TG Fort Nelson Reply Comments
Friday, December 12, 2008	Commission Decision

1.7 Conclusion

Terasen Gas has performed efficiently and effectively over many years in delivering value to its TG Fort Nelson customers. The increase in rates being sought by the Company, effective January 1, 2009, is reasonable and just and is necessary to cover the cost of service to the customers in the TG Fort Nelson area.

SECTION 2 – HISTORY AND OVERVIEW

2.1 Terasen Gas Background

Terasen Gas is one of the largest natural gas distribution companies in Canada, based on the number of customers and service area. Terasen Gas, through its parent company Terasen Inc., is a wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada.

Terasen Gas is responsible for the procurement and supply of natural gas to the majority of its customers. For customers in all of its service areas, the Company purchases its supply of gas from a number of producers, aggregators and marketers. Terasen Gas also contracts with various providers for service on upstream pipelines, capacity in underground storage facilities and various types of peaking and gas supply cost mitigation arrangements. The gas supply, transmission and distribution functions of Terasen Gas have always focused on activities that are integral to the safe, reliable and efficient running of utility operations. Beyond the front line activities such as responding to emergencies, constructing, installing and operating the transmission and distribution system, there are a number of key support functions. These include planning and designing facilities, corrosion control, metering, meter reading, leak surveying, right of way management and materials management and distribution.

Also important are the systems and services that allow Terasen Gas to meet its responsibilities effectively in today's dynamic business environment. These supporting systems include customer billing and customer care, marketing, information technology, municipal, community and aboriginal relations, legal, risk management, environment, health and safety, regulatory, human resources and finance/accounting.

2.2 TG Fort Nelson Background

The natural gas distribution system in the Fort Nelson area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and other companies and continued as BC Gas Inc., later BC Gas Utility Ltd. and now Terasen Gas Inc.

Rates have been set separately for TG Fort Nelson from the date the company was acquired to the present. Terasen Gas (as BC Gas Utility Ltd.) sought regulatory consolidation of TG Fort Nelson with the remainder of the Company in its 1992 Revenue Requirement Application, but the application was not approved. Since then, TG Fort Nelson has been excluded from the Company's general revenue requirement applications and Performance Based Ratemaking ("PBR") plans.

Since 1985, rate changes have been largely limited to those approved from time to time for flow through cost of gas increases or decreases. The most recent revenue requirement change affecting the rates for delivery service in Fort Nelson was an increase of $265,000 approved by the Commission by Order No. G-27-08, leading to a 23.9 percent increase in delivery margin effective February 1, 2008. That revenue requirement change was primarily attributed to the downturn of forest industry affecting the industrial demand for the Fort Nelson region. Prior to the 2008 rate increase, there was a slight increase of $49,000 (1.08% increase in delivery rates), approved by Commission Order No. G-17-04, effective January 1, 2004.

Operations in Fort Nelson consist of a transmission lateral from the nearby Westcoast Energy Inc., (formerly owned by Duke Energy – BC Pipeline Division and now Spectra Energy) processing plant to the town of Fort Nelson together with a gas distribution system. Also included in the service area is the distribution system in Prophet River. Customers' rates in the Terasen Gas service areas other than TG Fort Nelson are not affected by this Application.

TG Fort Nelson's gas supply has typically been obtained through one contract. In recent years, the Company has used a small portion of its contracted gas storage capacity at Aitken Creek to improve the load factor of the Fort Nelson and to mitigate the impact of gas volatility for Fort Nelson customers. The diversity of Terasen Gas' overall gas supply portfolio has assisted over the years in providing favourable gas supply arrangements for TG Fort Nelson.

Gas cost recoveries within rates are based on forecast costs. Potential rate changes for the cost of gas are reviewed by the Commission on a quarterly basis and gas costs are passed on to customers without mark-up. The actual costs invariably differ from the forecast costs. Terasen Gas, consistent with past practice, will continue to defer any difference for TG Fort Nelson between the costs incurred to purchase the gas commodity and the gas cost recoveries collected through rates in the Gas Cost Reconciliation Account ("GCRA").

Customers in TG Fort Nelson have benefited and continue to benefit in various ways from being part of a much larger gas distribution company. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities;
- Access to low cost capital funding;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and
- Access to the commodity-related benefits of being in a company that is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs.

SECTION 3 – DEMAND AND REVENUE FORECAST

This section addresses the forecast of customer additions, energy demand and the resulting revenues and margins for 2009. Included is a review of the energy forecast methodology, as well as factors influencing customer additions and customer use rates.

The forecast of industrial volumes reflects the industrial survey conducted during the summer of 2008. Similarly, revenue and margin forecasts reflect the most recently approved rates.

3.1 Forecast Methodology

Consistent with the forecasting process followed by Terasen Gas for its other three service areas (Lower Mainland, Inland and Columbia), the forecasting process is comprised of three main components:

- Customer additions forecast;
- Average use per customer; and
- Industrial forecast.

The residential and commercial energy forecast, consisting of customers served under Rate Schedules 1, 2.1, and 2.2, is driven by the respective account and use per customer forecasts, while the industrial energy forecast incorporates customer survey data received from the one remaining customer served under Rate Schedule 25.

The customer additions forecast reflects prevailing macroeconomic circumstances affecting residential and commercial customers. The industrial forecast includes only the single remaining Rate Schedule 25 customer, Canfor's Tackama Mill.

Consistent with the methodology used across the service areas for Terasen Gas, the average use per customer is estimated for customers served under Rate Schedules 1, 2.1, and 2.2 and then is multiplied by the corresponding forecast of customers in each rate class to derive energy consumption. The industrial forecast continues to rely on historical data, sector analyses and customer-specific survey results.

Current rates are applied against the energy forecast to calculate the revenue forecast. The underlying assumptions and components of that forecast are discussed below.

3.2 Underlying Assumptions

The following assumptions were made about external influences when developing this forecast:

- Population growth experiences volatility - difficulties faced by the forestry industry affect the short term; growth in the oil and gas sector offset the long-term impacts; and
- Natural gas commodity prices will experience upward pressure over the short-term, but remain relatively stable over the long-term.

The latest population projection from BC Statistics shows an expected 1.7% increase in population for the TG Fort Nelson region from 2008 to 2009. This is lower than previous estimated growth rates (the expected growth from 2007 to 2008 was 3%). Although BC Statistics does not provide details on the basis for the specific changes in growth rates, there are two major factors assumed to be influencing growth in the region.

First, the difficulties faced by the forestry industry continue. In the Fort Nelson region, this includes the closure of Canfor's PolarBoard OSB Plant in the summer of 2008, which is expected to influence customer growth in the immediate future. Offsetting this, especially over the long term, is the continued growth of the oil and gas sector in Fort Nelson. With the unconventional shale gas deposits in the Horn River Basin having captured the interests of exploration and production companies and significant shale drilling activity expected over the next decade, the oil and gas sector is expected to continue to grow. Given that Fort Nelson is well positioned to service this industry, the region is expected to see increased growth over the long term. Given these factors, it is not unreasonable to assume customer additions will decline in the short term, but increase over the long term.

With respect to industrial firms that use natural gas in Fort Nelson, there remains only one customer served under Rate Schedule 25 in the region that accounts for approximately 28% of the TG Fort Nelson demand in 2009. For the purpose of determining rates in 2009, the assumption is that the remaining single customer served under Rate Schedule 25, Canfor's Tackama Mill, will continue to operate its facility.

3.3 Customer Additions

The forecast of residential account additions is based on household formation data which is statistically linked with actual account additions to model annual account growth on a service-area basis. The forecast of household formations is then applied to obtain the expected number of additions and adjusted for actual customer counts. In addition to the BC Statistics 2008 Household Formation forecast, the local municipal website is reviewed as well as overall trends in key industries that affect the region such as forestry, energy and tourism.

Table 3.3a below provides a summary of the residential, commercial and industrial year-end net customer additions since 2005. Table 3.3a presents normalized actual values for 2005 through to 2007. The 2008 projection for year-end includes actual values up to April 30, 2008. The 2009 values represent the forecast.

Table 3.3a - TG Fort Nelson Customer Additions (Year-End Net)

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	26	3	7	12	6	9
Rate 2.1	19	9	6	5	3	3
Rate 2.2	0	1	1	0	-2	0
Rate 25	0	0	0	0	-1	0
Total	**45**	**13**	**14**	**17**	**6**	**12**

Fort Nelson has experienced variations in the rate of customer additions due to the dynamics of the energy and forestry industries. Also, new housing tends to be added by sub-division which can add a significant number of new customers in a given year, but may then impact the subsequent year. For 2009, customer additions are expected to moderate as the uncertainty associated with the forestry industry may cause a delay in home purchasing decisions.

The total number of customers has been growing within the residential and commercial rate classes as seen below in Table 3.3b. There were many new homes built in 2003 and in 2004 in Fort Nelson, with triple the rate of new home construction compared with the previous two-year period. This boom in construction accounts for the increase in the total number of customers in 2003 and 2004. Since that time, construction has moderated, but overall, the region continues to grow.

Table 3.3b – TG Fort Nelson Year-End Customers

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	1,918	1,921	1,928	1,928	1,934	1,943
Rate 2.1	393	402	408	408	411	414
Rate 2.2	28	29	30	30	28	28
Rate 25	2	2	2	2	1	1
Total	**2,341**	**2,354**	**2,368**	**2,368**	**2,374**	**2,386**

3.4 Use per Customer (Core Customers)

Individual use per customer projections are developed for each rate class by considering the following factors:

- Recent historical weather normalized use per account;
- Efficiency improvements – appliance and insulation upgrades

The decline in residential use rates experienced over the last several years throughout the province is also evident in Fort Nelson. The projection for 2008 shows a slight decline from 2007 use rates. For 2009, customers served under Rate Schedules 1, 2.1, and 2.2 have been lowered by 1% with respect to what is projected for 2008. This expected decline is driven by efficiency gains from newer homes and appliances, a scenario that is similar to what has been experienced in other Terasen Gas regions. A summary of historic and forecast use per customer rates for core customers are set out below in Table 3.4 and have been used in the preparation of the 2009 forecast.

Table 3.4 - TG Fort Nelson Use per Customer Rates (in GJ/annum)

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	154.3	142.3	141.9	148.8	141.7	140.3
Rate 2.1	499	491	472	503	479	474
Rate 2.2	3,643	3,276	3,084	3,312	3,189	3,158

3.5 Energy Forecast

3.5.1 Residential/Commercial

The residential and commercial energy forecast is calculated by multiplying the use per customer rate by the total number of customers. Compared with the projection for 2008, the total residential energy consumption is expected to decrease marginally from 274 terajoules (TJs) to 271 TJs in 2009. Commercial consumption is also forecast to decrease marginally to 283 TJs in 2009 as compared to 288 TJs in 2008. The forecast for each year is provided in Table 3.5.2 below. Overall, residential and commercial energy consumption has been holding relatively stable since 2004, with decreases in use rates being offset by growth in customer additions.

3.5.2 Industrial

There remains only one industrial customer served under Rate Schedule 25 in the TG Fort Nelson region, Canfor's Tackama Plywood facility. Recent developments in the U.S. housing markets and foreign exchange rates have caused difficulties within the forestry industry. A number of closures and curtailments have been announced by forestry companies, which include the recent closure of Canfor's PolarBoard OSB Plant in Fort Nelson in the summer of 2008. On January 18, 2007, Canfor had announced that both of its facilities in Fort Nelson would close in 2008; however on February 25, 2008 Canfor announced that after coming to agreement on cost cutting concessions from the union representing mill workers, suppliers and the provincial government, it was reversing its decision and would keep Tackama Plywood facility open. However, due to lumber market conditions, Terasen Gas cannot say with any certainty that this facility will not be idled or closed indefinitely at some point in the future.

As Table 3.5.2 below demonstrates, industrial volumes have been declining for the past several years with the projection for 2008 following that trend. Slowdown in the U.S. housing market and strengthening of the Canadian currency has affected the lumber industry, which in turn has resulted in the closure of the PolarBoard OSB Plant in Fort Nelson. This is the primary reason for the most recent decline in industrial volumes. Based on survey results from Canfor for the Tackama Mill, it is expected that in 2009, consumption will stabilize at levels similar to what is being experienced in 2008.

Table 3.5.2 - TG Fort Nelson Energy Demand Forecast (in TJ/annum)

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	291	271	272	285	274	271
Rate 2.1	193	191	190	205	197	195
Rate 2.2	102	95	90	99	91	88
Rate 25	365	349	264	265	231	214
Total	**951**	**906**	**816**	**854**	**793**	**768**

3.6 Revenue and Margin Forecast

3.6.1 Revenue Forecast

Revenue forecasts for each customer class are developed from the total energy forecasts and the applicable rates currently in effect for December 2008. The increase in revenue for 2009 is attributable to both customer additions for customers served under Rate Schedules 1 and 2.1 and the delivery rate rebate (valid till December 31, 2008 for customers served under Rate Schedules 1, 2.1, and 2.2), which offsets the decline in use per customer rates as shown in Table 3.6.1.

Table 3.6.1 below summarizes historical and forecast revenues, excluding RSAM rider, for 2005 to 2009 by rate class. Year 2005 through 2007 represent actual normalized values. Year 2008 decision, 2008 projection and 2009 forecast represent revenues at existing approved rates.

Table 3.6.1 - TG Fort Nelson Revenue Forecast

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	$ 2,445	$ 2,484	$ 2,298	$ 2,461	$ 2,611	$ 2,775
Rate 2.1	$ 1,701	$ 1,794	$ 1,634	$ 1,822	$ 1,908	$ 2,040
Rate 2.2	$ 813	$ 863	$ 747	$ 851	$ 849	$ 893
Rate 25	$ 322	$ 309	$ 235	$ 295	$ 250	$ 231
Total	**$ 5,281**	**$ 5,450**	**$ 4,914**	**$ 5,429**	**$ 5,619**	**$ 5,938**

3.6.2 Margin Forecast

Table 3.6.2 below summarizes historical and forecast margins for 2005 to 2009 by rate class. The results shows that 2009 total margin at existing rates, excluding riders, is expected to decrease slightly from 2008 projected value due to declining use per customer rates and a significant increase in the cost of gas.

Revenues for customers served by Rate Schedule 25 include an allocation of unaccounted for gas ("UAF"), which is excluded from the margin calculations.

Table 3.6.2 - TG Fort Nelson Margin Forecast

	2005 Normal	2006 Normal	2007 Normal	2008 Decision	2008 Projection	2009 Forecast
Rate 1	$ 415	$ 426	$ 428	$ 504	$ 478	$ 486
Rate 2.1	$ 359	$ 335	$ 330	$ 414	$ 385	$ 389
Rate 2.2	$ 111	$ 134	$ 130	$ 169	$ 146	$ 145
Rate 25	$ 332	$ 304	$ 239	$ 287	$ 228	$ 209
Total	**$ 1,217**	**$ 1,199**	**$ 1,127**	**$ 1,375**	**$ 1,238**	**$ 1,229**

3.7 RSAM

In the 2004 Revenue Requirements Application, Terasen Gas sought approval from the Commission to implement a Revenue Stabilization Adjustment Mechanism ("RSAM") account for TG Fort Nelson to capture variations in the delivery margin for residential, commercial and industrial rate classes. Commission Order No. G-17-04, dated February 5, 2004, granted approval for the implementation of the RSAM account. A RSAM deferral account accumulates the annual RSAM debits and credits with one third of the net balance being recovered or refunded in the following year via a positive or negative rate rider.

The RSAM for TG Fort Nelson differs from the RSAM of the other regions of Terasen Gas in that it includes the customers served under Rate Schedule 25. The RSAM for TG Fort Nelson customers served under Rate Schedule 25 is based on forecast delivery minus actual delivery multiplied by the delivery rate. The rationale for requesting the inclusion of customers served under Rate Schedule 25 in the TG Fort Nelson RSAM pertains to the specific local circumstances in TG Fort Nelson relative to the rest of the Terasen Gas system. The margin from customers served under Rate Schedule 25 comprises approximately 20% (based on the 2008 forecast) of the total forecast delivery margin in TG Fort Nelson. A second factor pertains to the TG Fort Nelson rate structure where the margin collection from customers served under Rate Schedule 25 is entirely volumetric except for the monthly Administrative fee. In the other service areas of the Company, a considerable percentage of the charges for delivery service in the industrial classes are on a fixed basis making use of demand charges and other fixed rate tariffs. A third factor in TG Fort Nelson is that the lack of diversity in the energy demand of the customers served under Rate Schedule 25 (historically forestry sector) making margin collection more volatile as it is subject to the variations of a single industry that is cyclical. In the rest of the Terasen Gas system, there are various industries and services represented as well as a large number of customers.

Based on federal and provincial legislated income tax rate changes the annualized income tax rate for 2008 is 31% (for details, refer to Section 6.3). A further reduction in combined income tax rates results in an income tax rate of 30% for 2009, effective January 1, 2009. The RSAM rate rider based on the effective combined income tax rate for 2009 is estimated to be $0.143 (an increase of $0.027) as set out in Table 3.7 below.

Table 3.7 – Calculation of Amortization of RSAM (Rider 5)

Line No.	Particulars	Annual Volumes (TJ)	Amortization	Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)
1	**RSAM (Rider 5) Calculation**			
2				
3	Rate 1 - Residential	270.5		$0.143
4	Rate 2.1 - Small Commercial	195.0		$0.143
5	Rate 2.2 - Large Commercial	88.4		$0.143
6	Rate 3.1 - Industrial Service	0.0		$0.143
7	Rate 3.2 - Industrial Service	0.0		$0.143
8	Rate 3.3 - Industrial Service	0.0		$0.143
9	Rate 25 - Large Commercial Transportation	213.9		$0.143
10		**767.8**	**$ 109,456** (1)	
11				
12				
13	**"Would be" Rider for 2009 (revised Rate 25 volumes & recorded 2008 balances)**			**$0.143**
14	**Approved Rider for 2008 (BCUC Order G-27-08)**			**$0.116**
15	**Rider 5 Increase/(Decrease)**			**$0.027**
16				
21				
22	**Note 1: RSAM Rider Change (Assumptions)**			
23				
24	**1) Recorded 2008 RSAM and RSAM interest balance**			
25	**2) Rate 25 Annual Volume Forecast 213.9 TJ**			
26				
27	**Note 2: RSAM Rider Change (To be Approved)**			
28				
29	After offsetting the 2008 RSAM rider recovery, the RSAM account including interest is now projected			
30	to be $229,857. Pursuant to the Commission Order No.G17-04, Fort Nelson would amortize the RSAM			
31	balance over the subsequent three-years for recovery. Accordingly the net-of-tax RSAM balance to be			
32	amortized in 2009 is $76,619. On a pre-tax basis, this amounts to $109,456 or $0.143/GJ, which is a $0.027/GJ			
33	increase from the existing level of $0.116/GJ.			
34				
35	Amortization = 1/3 of Projected December 31, 2008 RSAM Balance			
36	= 1/3 * ($224,324 RSAM + $5,533 RSAM Interest)			
37	= $76,619 Net-of-tax amortization			
38				
39	Gross Amortization = Net-of-tax amortization / (1 - tax rate)			
40	= $76,619 / (1 - 30.0%)			
41	= $109,456			

3.8 Summary

The forecast supporting the 2009 Revenue Requirements and Rate Application reflects a consistency in forecasting methodology across the Terasen Gas service areas and incorporates the following:

- Revenues at current rates for 2008;
- Customer counts and use per customer rates adjusted to reflect actual results consistent with the Terasen Gas Annual Review material preparations; and
- Industrial demand and revenues reflect current customer survey responses.

SECTION 4 – COST OF GAS

The cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The gas cost recovery charge embedded within rates is based on the forecast gas costs for the next 12-month period, including the current balance within the Gas Cost Reconciliation Account ("GCRA"). As the actual commodity costs invariably differ from the forecast costs, consistent with past practice, any differences between the costs incurred to purchase gas and the gas cost recoveries collected through rates will continue to be collected in the GCRA.

The TG Fort Nelson gas cost recovery charge is the same for all sales rate classes and the current gas cost recovery charge is $10.151 per GJ, approved by Commission Order No. G-95-08, dated June 13, 2008 and effective July 1, 2008.

Consistent with established Commission practice, Terasen Gas will continue to review and report on the gas costs and the gas cost recovery rates for TG Fort Nelson on a quarterly basis and, as necessary, will make application for any rate changes to recover the cost of gas. (The document entitled, "British Columbia Utilities Commission – Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance", issued as Appendix I to Commission Letter No. L-5-01, dated February 5, 2001, outlines the quarterly reporting process.)

Terasen Gas will file the Third Quarter 2008 Gas Cost Report for TG Fort Nelson by the end of the first week of September 2008.

SECTION 5 – OPERATING AND MAINTENANCE EXPENSES

5.1 Calculation Methodology

For financial reporting purposes, the operating and maintenance ("O&M") costs for TG Fort Nelson are included in overall operating and maintenance expenses of Terasen Gas.

To determine the TG Fort Nelson-related total O&M costs, both actual and forecast, the following process was used:

- Determine the TG Fort Nelson direct O&M costs. These costs consist of labour, vehicle usage, materials and services used in direct system operations and customer billing related costs, determined on a per customer basis.

- Allocate O&M costs from those Terasen Gas business units that provide functional support to TG Fort Nelson. These shared services costs would include charges related to Marketing, Information Technology, Gas Supply and Transmission, Finance and Regulatory, Facilities and Logistics, Legal and Government Affairs, Human Resources and the office of the President. The allocation basis used up to and including 2007 was TG Fort Nelson's sales volumes as a percentage of Terasen Gas' sales volumes. The resulting allocation factor was 0.4% to determine the TG Fort Nelson portion of the Shared Services.

  Effective 2008, by Order No. G-27-08, in the TG Fort Nelson 2008 Revenue Requirements Application, the Commission approved:

  > "*Shared Services received by TG Fort Nelson from TGI for 2008 are to be allocated to the Company on the basis of customers…"*

  The Shared Services allocation was based upon the 2008 projection of total customers served by Terasen Gas was 829,970 and TG Fort Nelson was 2,341 (refer to the 2008 Revenue Requirements Application, Response to Commission Information Request No. 2, Question 22.2). The calculation results in an allocation factor of 0.3% which was used for 2008 rates. The same 0.3% allocation factor was used for 2009.

- An overhead capitalization rate of 16% is applied to gross O&M for TG Fort Nelson to arrive at the net O&M costs which is consistent with past practice and approved for Terasen Gas.

Table 5.1 below provides a combined resource view of the direct and allocated O&M costs for recent years' spending, along with the forecast budget for 2009. Gross O&M spending for 2009 determined by taking into consideration both 2007 actual and 2008 projected spending levels.

Table 5.1 - TG Fort Nelson Operating and Maintenance Expenses

Table E.1
TG Fort Nelson Operating & Maintenance Expenses
Resource View ($'000s)

	2008 Decision	**2008** Projected	**2009** Forecast
Labour Costs			
M&E Costs	145	139	145
COPE Costs	53	51	53
IBEW Costs	240	239	247
Total Labour Costs:	438	428	444
Non-Labour Costs			
Vehicle Costs	52	52	59
Employee Expenses	33	32	33
Materials	22	22	23
Computer Costs	24	23	24
Fees and Administration Costs	63	59	62
Contractor Costs	165	163	166
Facilities	29	28	29
Recoveries and Other Revenue	(50)	(47)	(49)
Total Non-Labour Costs:	338	330	346
Total Gross O & M Expenses	776	759	790
Less Capitalized Overhead	(124)	(121)	(126)
Total Net O & M Expenses	$ 652	$ 637	$ 664

5.2 Other Revenue

There are three components of Other Revenue:

- Late Payment Charges;
- Revenue from Service Work; and
- Other.

5.2.1 Late Payment Charges

Late payment charges for 2009 forecast are based on the 2007 and 2008 (up to April 30, 2008) actual accounts receivable as a percentage of the billed revenue, resulting in approximately 0.6% of the residential and commercial revenue forecast for 2009.

5.2.2 Revenue from Service Work

This revenue is generated primarily from connections charges and transfer fees. Customer additions are levied an $85 charge per service. As well, account transfers are assessed a $25 fee.

5.2.3 Other

Revenue from Other sources is comprised mostly of NSF (non-sufficient funds) Cheque administration fees. Each returned cheque is levied a $20 fee.

Revenue from Late Payment Charges, Service Work and Other sources in the year 2009 as compared to 2008 decision and 2008 projected value is shown in Section 10, Schedule 10.

SECTION 6 – TAXES, DEFERRED CHARGES, DEPRECIATION AND AMORTIZATION EXPENSE

6.1 Property Taxes

Property taxes were levied against the Company by Provincial, Municipal and other local governments. The Property Tax deferral account collects all variances from the 2004 Decision Test Year amount (2004 - 2007). Future deferred property tax will based on the variance of actual payments less approved 2008 forecast expense to be included in determining the rates for 2008 and following years until the next revenue requirement application.

- ***1% Tax In Lieu of General Municipal Taxes ("1% Tax")***
  The 1% tax in lieu of general municipal taxes ("1% Tax) is calculated by multiplying the amount of revenues collected within municipal boundaries by 1%. Payments of the 1% tax to municipalities are lagged relative to increases and decreases in revenues due to provisions in the Local Government Act. Revenues are generally expected to increase until 2011.

- ***General, School and Other***
  Property taxes include general, school and other property taxes. For 2008, assessed values are estimated using 2008 actual assessments. The assessments for land and improvements, including pipeline, are anticipated to present general market increases between 3% and 8%. These increases are primarily related to market value increases in land as well as increased costs in construction materials (i.e. steel) and increased labour costs. Mill rates are expected to decline slightly as a partial offset to the increasing assessment values.

In 2008 significant events include:

1) An increase in office land market value of $39,000 (25%);
2) Transmission pipeline rates increased by 4.5%; and
3) Distribution pipeline rates increased by 4.5%.

In 2009 significant events taken into account include:

1) Increases in market value properties is expected to slow, Increases in fee properties are expected to be higher than right of way increases which are based on provincial averages;

2) Cost drivers for pipeline material and labour costs are expected to continue to Increase at 4%; and

4) Additions are estimated to be $105,000 in 2008 based on averages reported from 2000 to 2007. For 2008 they are allocated as follows:

   a. Fort Nelson First Nation: $20,000
   b. Town of Fort Nelson: $55,000
   c. Fort Nelson Rural: $30,000.

For 2009 growth in distribution pipeline and service cost additions are expected to increase by 3.2%.

6.2 Deferred Charges, Depreciation and Amortization

6.2.1 Deferred Charges

Unamortized Deferred Charges are carried in the regulatory schedules on a net-of-tax basis. Schedule 17.2 under Section 10 shows the 2009 Forecast for Unamortized Deferred Charges and Amortization.

6.2.2 Depreciation and Amortization

Accumulated Depreciation for 2009 has been updated for the 2008 projected closing balance. Commission approved depreciation rates and amortization periods are used for all accounts. Depreciation rates affecting measurement and computer software accounts reflect the approved changes in Section 5.2 of Commission Order No. G-17-04, dated February 5, 2004. Meters are depreciated at 3.57% per year.

6.3 Income Tax

Income tax expense is determined based on taxable earnings calculated on the basis of revenues and costs in accordance with the applicable provisions of the *Income Tax Act*, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes.

Based on the income tax rate changes enacted by the federal government, the corporate income tax rate for year 2008 was forecast to be 31.5%, effective January 1, 2008. This rate was approved by the Commission as per Commission Order No. G-158-07 dated December 14, 2007. In June 2008 a 1% income tax rate reduction from 31.5% to 30.5% was enacted by the B.C. government, effective July 1, 2008 to December 31, 2008. As a result, the annualized income tax rate for 2008 is 31%.

Based on the income tax rate changes enacted by B.C. government in June 2008, the income tax rate for 2009 is forecast to be 30%, effective January 1, 2009. Even though there is a 1% reduction in the income tax rate from 2008 to 2009, income tax for year 2009 is higher than the 2008 decision. This is due in part to higher taxable income at revised rates as well as a reduction in timing differences (please refer to Section 10, Schedules 5 and 12).

6.3.1 Carbon Tax

Effective July 1, 2008, the province of British Columbia introduced a tax on the purchase or use of fossil fuels including gasoline, diesel fuel, natural gas, home heating fuel, propane, and coal (the "Carbon Tax").

Terasen Gas submitted Carbon Tax and Provincial Tax treatment application dated May 15, 2008, which was approved by the Commission Order No. G-88-08 dated June 10, 2008. In the application, the Company took position that estimated $700 of net expenses incurred due to Carbon Tax for 2008 in Fort Nelson is immaterial and there would be no request to recover those expenses. It is estimated that savings as a result of the changes to the Provincial Corporate Income Tax rate mentioned above would be offset by the additional expenses incurred by the Company resulting from Carbon Tax through the Company's own-use of Natural Gas in line heaters.

SECTION 7 – CAPITAL REQUIREMENTS AND RATE BASE

7.1 Capital Expenditures

Capital expenditures are required to provide safe and reliable natural gas service to new and existing customers. Table 7.1 below summarizes TG Fort Nelson's forecast capital requirements for 2009 forecast compared to the decision and projection for 2008. These expenditures exclude Contributions in Aid of Construction ("CIAC"), Allowance of Funds Used During Construction ("AFUDC"), and capital projects which are subject to Certificate of Public Convenience and Necessity ("CPCN") applications. At this time, there are no identified capital projects that require a CPCN.

Table 7.1\ - TG Fort Nelson Capital Additions Summary ($'000's)

	2008 Decision	2008 Projection	2009 Forecast
Customer Additions	17	6	12
Transmission			
Mains	-	-	-
Total Transmission	-	-	-
Distribution			
Structures & Improvements	-	-	20
Services	28	28	35
House Regulator & Meter Installation	7	7	4
Mains	24	31	59
Measuring & Regulating Equipment	-	147	50
Meters	4	4	3
Small Tools & Equipment	16	16	8
Total Distribution	79	233	179
Total Capital Additions	79	233	179

The 2008 forecast Total Capital Additions are $154,000 greater than the 2008 decision. This is mainly attributed to Measuring & Regulating Equipment where approximately $100,000 of the expenditures is for the upgrade of the Fort Nelson Odorizer Station. Additional equipment installation is required to address concerns that exist at this inlet from Spectra. Currently, the maximum operating pressure of the Fort Nelson pipeline system is less than that of the Spectra system. This condition requires installation of control valves and overpressure protection device in order to reduce pressure from the Spectra system. While the installation of control valves occurs, the Company intends to remove an obsolete pipeline valve that has a minor leak. Also planned is installation of new piping, hydrogen sulphide (H2S) monitoring, and gas flow shut off equipment to manage and prevent hazardous levels of H2S from entering the Fort Nelson distribution systems. There have been a number of occurrences where gas having a high H2S level has entered the Fort Nelson system. Discussions have been occurring with Spectra with regards to the possible installation of devices within their system that would accomplish the same objective and mitigate the need for Terasen Gas to install the equipment on its own facilities. The upgrades to the Fort Nelson Odorizer Station are anticipated to be completed in 2009.

The remaining 2008 expenditures in Measuring & Regulating Equipment pertain to obsolete filter upgrades at the Fort Nelson Station and Muskwa Station as well as a flame safeguard system upgrade at the Muskwa Station. In 2009, capital expenditures in Structures and Improvements are required to replace a shop roof.

7.2 Working Capital

The major components of the working capital allowance have been divided into two categories: Cash Required for Operating Expenses and Other Working Capital. Please refer to Section 10, Schedules 18.1 and 18.4 for total cash required for operating expenses and other working capital required for the year 2009 at revised rates and its comparison to 2008 Decision and 2008 projected values.

7.2.1 Cash Required for Operating Expenses

Cash Required for Operating Expenses will continue to be determined using the lead/lag methodology established in 1992 with BC Gas Utility Inc.'s 1992 Revenue Requirement Application. The revenue lead days for TG Fort Nelson customers reflect the billing service provided by CustomerWorks. This methodology was used in the 2008 revenue requirements application. Total cash required for operating expenses for year 2009 at revised rates is $51,000 (Please refer to Section 10, Schedule 18.1).

7.2.2 Other Working Capital

Other working capital items include:

- Minimum cash balances;
- Customer deposits;
- Reserve for bad debts;
- Employee withholdings; and
- Inventories.

The forecast 2009 costs for these items have been calculated based on historical levels for inventories and employee withholdings. Customer deposits and reserve for bad debts have been projected for 2008 and forecast for 2009 based on customer additions and customer deposit requirements. Reserve for bad debts has been forecast based on forecast revenue and historical bad debt experience. Please refer to Section 10, Schedule 18.1.

7.3 Rate Base

Table 7.3a below summarizes total utility rate base and rate base per customer for TG Fort Nelson in 2009 Application as compared to 2008 Decision. The table shows that rate base per customer for 2009 has increased by 4.65%.

Rate base per customer for 2009 as compared to 2008 projection has increased by 3% (refer to Table 7.3b), which is consistent with the rate of inflation. For details refer to Section 10, Schedule 2 and Schedule 3.

Table 7.3a - TG Fort Nelson Rate Base per Customer

	2008 Decision	2009 Application	Difference	% Change
Rate Base (in 000's)	$5,154	$5,426	$272	5.28%
Avg. # of Customers	2,341	2,355	14	0.60%
Rate Base / Customer	$2,202	$2,304	$102	4.65%

Table 7.3b – TG Fort Nelson Rate Base per Customer

	2008 Projected	2009 Application	Difference	% Change
Rate Base (in 000's)	$5,297	$5,426	$129	2.44%
Avg. # of Customers	2,372	2,355	-17	-0.72%
Rate Base / Customer	$2,233	$2,304	$71	3.17%

SECTION 8 – FINANCING AND CAPITAL STRUCTURE

TG Fort Nelson and the other three Terasen Gas service areas (Lower Mainland, Inland and Columbia) share the same debt and equity percentages for its capital structure: 64.99% debt and 35.01% equity. Please refer to Section 10, Schedule 6 for Long-Term Debt, Unfunded Debt and Common Equity values for year 2009 mentioned below as compared to 2008 Decision and 2008 Projected values.

8.1 Long Term Debt

The average embedded cost of long term debt for TG Fort Nelson average is 7.223% and represents approximately 58% of the capital structure funding rate base.

8.2 Unfunded Debt

The cost of Unfunded Debt for TG Fort Nelson is 4.25%. Unfunded debt represents approximately 8% of the capital structure funding rate base.

8.3 Common Equity

The common equity component of the capital structure is 35.01%. The calculations in this Application have made use of the recently approved Return on Equity ("ROE") of 8.62% for 2008 (Commission Letter L-93-07, dated November 22, 2007). However, if the ROE mentioned above is changed in December 2008 (i.e. when the Commission updates the generic ROE mechanism calculation), the final revenue deficiency and customer rates could be adjusted at that time to be effective January 1, 2009.

SECTION 9 – REVENUE REQUIREMENT AND CUSTOMER RATES

Table 9a below shows the progression from the bundled sales and Transportation Service rates approved for 2008 to the applied for rates effective January 1, 2009 for customers served under Rate Schedules 1, 2.1, 2.2, and 25. TG Fort Nelson provides service to all its customers under these rate schedules. The rate increases proposed for residential and commercial customers represent an increase of 3% on a total bill basis (refer to Section 10, Schedule 1.1). The proposed increase for customers served under Rate Schedule 25 is 17%.

Table 9a - Proposed Tariff Rate Change & Rate Class Revenue Recovery

Line No.	Particulars	Tariff @ 2008 Rates	Less: Delivery Rate Rebate (in $/GJ)	Less: RSAM Recovery Charge (in $/GJ)	Less: Average Cost of Gas	Delivery Margin	Margin Rate Increase	Add: Average Cost of Gas	Add: Revised RSAM Recovery Charge	Tariff @ Revised Rates Jan 1/09
1	**Residential**									
2	1st Blk ≤ 2 GJ $ / Month	$ 22.39	$ 0.10	$ (0.23)	$ (16.92)	$ 5.34	$ 1.16	$ 16.92	$ 0.29	$ 23.71
3	2nd Blk Next 28 GJ $ / GJ	$ 10.017	$ 0.050	$ (0.116)	$ (8.462)	$ 1.489	$ 0.245	$ 8.462	$ 0.143	$ 10.339
4	3rd Blk Excess of 30 GJ $ / GJ	$ 9.974	$ 0.050	$ (0.116)	$ (8.462)	$ 1.446	$ 0.238	$ 8.462	$ 0.143	$ 10.289
5										
6	**General Service - Small Commercial**									
7	1st Blk ≤ 2 GJ $ / Month	$ 33.30	$ 0.13	$ (0.23)	$ (16.92)	$ 16.28	$ 3.13	$ 16.92	$ 0.29	$ 36.62
8	2nd Blk Next 298 GJ $ / GJ	$ 10.176	$ 0.066	$ (0.116)	$ (8.462)	$ 1.664	$ 0.272	$ 8.462	$ 0.143	$ 10.541
9	3rd Blk Excess of 300 GJ $ / GJ	$ 10.124	$ 0.066	$ (0.116)	$ (8.462)	$ 1.612	$ 0.263	$ 8.462	$ 0.143	$ 10.480
10										
11	**General Service - Large Commercial**									
12	1st Blk ≤ 2 GJ $ / Month	$ 33.30	$ 0.13	$ (0.23)	$ (16.92)	$ 16.28	$ 3.13	$ 16.92	$ 0.29	$ 36.62
13	2nd Blk Next 298 GJ $ / GJ	$ 10.176	$ 0.066	$ (0.116)	$ (8.462)	$ 1.664	$ 0.272	$ 8.462	$ 0.143	$ 10.541
14	3rd Blk Excess of 300 GJ $ / GJ	$ 10.124	$ 0.066	$ (0.116)	$ (8.462)	$ 1.612	$ 0.263	$ 8.462	$ 0.143	$ 10.480
15										
16	**Transportation Service**									
17	1st Blk ≤ 20 GJ $ / GJ	$ 1.407	$ -	$ -	$ (0.101)	$ 1.306	$ 0.220	$ 0.101		$ 1.627
18	2nd Blk Next 260 GJ $ / GJ	$ 1.304	$ -	$ -	$ (0.101)	$ 1.203	$ 0.203	$ 0.101		$ 1.507
19	3rd Blk Excess of 280 GJ $ / GJ	$ 1.063	$ -	$ -	$ (0.101)	$ 0.962	$ 0.165	$ 0.101		$ 1.228
20	Minimum Delivery Charge per Month	$ 1,076.00				$ 1,076.00	$ 183.00			$ 1,259.00
21										
22	Administration Charge	$ 202.00	$ -	$ -		$ 202.00	$ -			$ 202.00
23	RSAM Recovery Charge	$ 0.116	$ 0.050	$ (0.116)	$ -	$ 0.050		$ -	$ 0.143	$ 0.193

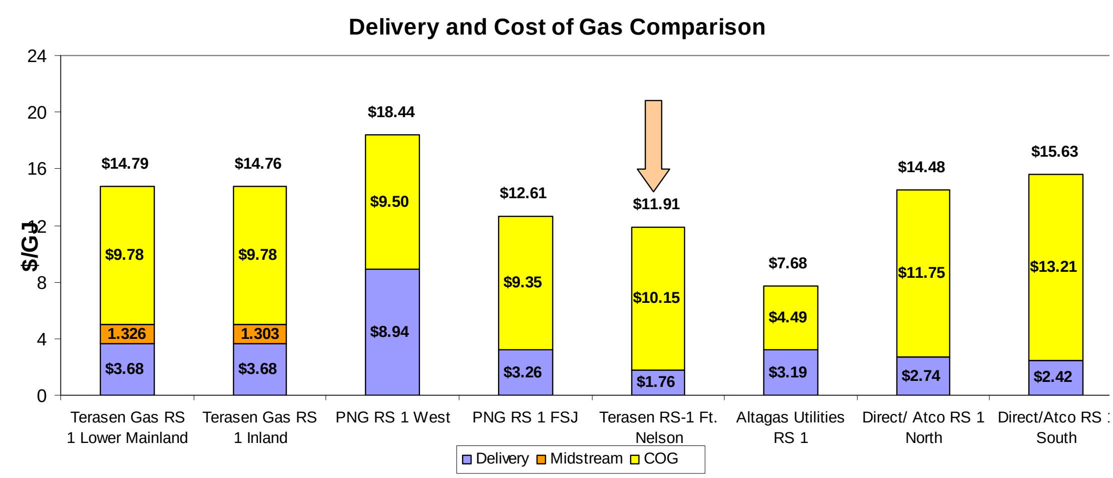
TG Fort Nelson does not have any customers served under Rate Schedules 2.3, 2.4, 3.1, 3.2 and 3.3. The Company proposes to increase the delivery component of the rates by the general margin percentage increase of 17%**,** except for customers served under Rate Schedule 2.4 which has no specified rate for NGV compression/dispensing service. The permanent proposed rate changes and rates effective January 1, 2009 based on the Application material for these rate classes are shown below on Table 9b.

Table 9b - Proposed Tariff Rate Change & Rate Class Revenue Recovery

Line No.	Particulars	Tariff @ 2008 Rates	Less: RSAM Recovery Charge	Less: Average Cost of Gas	Delivery Margin	Margin Rate Increase	Add: Average Cost of Gas	Add: Revised RSAM Recovery Charge	Tariff @ Revised Rates Jan 1/09
						17.02%			
1	**Rate Class 2.3 - Natural Gas Vehicle Fuel Service**								
2	1st Blk ≤ 2 GJ $ / Month	$ 33.47	$ -	$ (16.92)	$ 16.55	$ 2.82	$ 16.92	$ -	$ 36.29
3	2nd Blk Next 298 GJ $ / GJ	$ 10.495	$ -	$ (8.462)	$ 2.033	$ 0.346	$ 8.462	$ -	$ 10.841
4	3rd Blk Excess of 300 GJ $ / GJ	$ 10.443	$ -	$ (8.462)	$ 1.981	$ 0.337	$ 8.462	$ -	$ 10.780
5									
6	**Rate Class 3.1 / 3.2 - Industrial Service < 360,000 GJ per Year**								
7	Delivery Charge								
8	1st Blk ≤ 20 GJ $ / GJ	$ 1.407	$ -	$ -	$ 1.407	$ 0.239	$ -		$ 1.646
9	2nd Blk Next 260 GJ $ / GJ	$ 1.304	$ -	$ -	$ 1.304	$ 0.222	$ -		$ 1.526
10	3rd Blk Excess of 280 GJ $ / GJ	$ 1.063	$ -	$ -	$ 1.063	$ 0.181	$ -		$ 1.244
11	Minimum Month Delivery Charge	$ 1,076.00			$ 1,076.00	$ 183.00			$ 1,259.00
12									
13	Gas Cost Recovery Charge	$ 8.462		$ (8.462)	$ -	$ -	$ 8.462		$ 8.462
14	RSAM Rate Rider	$ 0.116	$ (0.116)		$ -	$ -	$ -	$ 0.143	$ 0.143
15									
16	**Rate Class 3.3 - Industrial Service ≥ 360,000 GJ per Year**								
17	Delivery Charge								
18	1st Blk ≤ 20 GJ $ / GJ	$ 1.407	$ -	$ -	$ 1.407	$ 0.237	$ -		$ 1.644
19	2nd Blk Next 260 GJ $ / GJ	$ 1.304	$ -	$ -	$ 1.304	$ 0.219	$ -		$ 1.523
20	3rd Blk Excess of 280 GJ $ / GJ	$ 1.063	$ -	$ -	$ 1.063	$ 0.178	$ -		$ 1.241
21	Minimum Month Delivery Charge	$ 1,076.00			$ 1,076.00	$ 183.00			$ 1,259.00
22									
23	Gas Cost Recovery Charge	$ 8.462		$ (8.462)	$ -		$ 8.462		$ 8.462
24	RSAM Rate Rider	$ 0.116	$ (0.116)		$ -		$ -	$ 0.143	$ 0.143

Figure 9 below compares TG Fort Nelson bundled sales rate for residential customers to other utilities in British Columbia and Alberta. Residential customers in the Fort Nelson Service Area still have lower delivery margin and average bundled sales rate as compared to Terasen Gas and most of other utilities shown below.

Figure 9 – Delivery and Cost of Gas Comparison at existing rates as of August 2008



SECTION 10 – FINANCIAL SCHEDULES

Schedule 1 – Summary of Rate Change Required

Line No.	Particulars	2008 Decision	2009 Forecast
1	**Rate Change Required**		
2	Gas Sales and Transportation Revenue at Existing Rates	$ 5,429	$ 5,938
3			
4	Less: Cost of Gas	(4,054)	(4,709)
5			
6	Gross/Delivery Margin	$ 1,375	$ 1,229
7			
8	Revenue Deficiency (Surplus)	$ -	$ 209
9			
10	Revenue Deficiency (Surplus) as a % of Gross Margin		17.02%
11			
12	Revenue Deficiency (Surplus) as a % of Total Revenue		3.52%

Schedule 1.1 – 2009 Revenue Requirement

Line No.	Particulars	2007 Actual Normalized		2008 Decision		2008 Projected		2009 @ Proposed Rates	
1	**Rate Base**								
2	Gas Plant in Service, Beginning	$	7,542	$	7,701	$	7,672	$	8,045
3	Gas Plant in Service, Ending		7,672		7,913		8,045		8,350
4									
5	Contribution in Aid of Construction, Beginning		(1,041)		(1,190)		(1,159)		(1,159)
6	Contribution in Aid of Construction, Ending		(1,159)		(1,200)		(1,159)		(1,159)
7									
8	Accumulated Depreciation, Beginning		(1,783)		(1,810)		(1,865)		(2,064)
9	Accumulated Depreciation, Ending		(1,865)		(2,010)		(2,064)		(2,273)
10									
11	Accumulated Amortization of Contribution in Aid of Construction, Beginning		509		550		543		554
12	Accumulated Amortization of Contribution in Aid of Construction, Ending		543		591		554		576
13									
14	Net Plant in Service, Mid-Year		5,209		5,272		5,284		5,435
15									
16	Adjustment to 13-Month Average		-				-		
17	Work in Progress, Not Attracting AFUDC		-		-		-		-
18	Construction Advances		-		-		-		-
19	Unamortized Deferred Charges		2		85		266		264
20	Cash Working Capital		(213)		(221)		(256)		(277)
21	Other Working Capital		17		18		4		3
22									
23	**Total Rate Base**	**$**	**5,015**	**$**	**5,154**	**$**	**5,297**	**$**	**5,426**

Schedule 1.1 – 2009 Revenue Requirement (Cont'd)

Line No.	Particulars	2007 Actual Normalized	2008 Decision	2008 Projected	2009 @ Proposed Rates
25	**Revenue Requirement / Deficiency (Surplus)**				
26	Cost of Gas	$ 3,786	$ 4,054	$ 4,381	$ 4,709
27	Operating & Maintenance Expense	701	652	637	664
28	Property Tax	98	125	125	158
29	Depreciation Expense	142	170	189	188
30	Amortization Expense	-	28	30	6
31	Other Operating Revenue	(39)	(38)	(36)	(45)
32	Income Tax Expense	22	49	47	61
33	Earned Return				
34	Short Term Debt Interest	27	21	25	17
35	Long Term Debt Interest	192	212	212	225
36	Return on Equity	131	156	99	164
37					
38	**Total Cost of Service at proposed rates**	**$ 5,061**	**$ 5,429**	**$ 5,708**	**$ 6,147**
39					
40	Sales Revenue @ **Existing Rates**	4,678	4,925	5,368	5,707
41	T-Service Revenue @ **Existing Rates**	235	239	250	231
42	RSAM	149		90	
43	Revenue Requirement approved		265		
44	**Revenue Deficiency / (Surplus)**	**$ (1)**	**$ -**	**$ 0**	**$ 209**
45					
46	**Revenue Deficiency / (Surplus) Applied to Sales Customers**				**$ 174**
47	**% Increase on Sales Revenue**				**3.0%**
48					
49	Total Revenue @ Existing Rates				$ 5,938
50	Gross Margin (Revenue - Cost of Gas) @ Existing Rates				$ 1,229
51					
52	% Increase on Gross Margin				17.0%

Schedule 1.2 – 2009 Revenue Requirement Details

Description	2008 Decision	2009 Forecast @ Existing Rates	Difference
Revenue			
Residential/Commercial	5,134	5,707	573
Transportation Service	295	231	(64)
Total Revenue:	**5,429**	**5,938**	**509**
Less:			
Cost of Gas	4,054	4,709	655
Gross Margin:	**1,375**	**1,229**	**(146)**
Cost of Service (excl. COG)			
O&M	652	664	12
Property Tax	125	158	33
Depreciation	170	188	18
Amortization	28	6	(22)
Income Tax	49	61	12
Interest Expense	233	243	10
Other Revenue	(38)	(45)	(7)
Return on Equity	156	164	8
Total Cost of Service:	**1,375**	**1,438**	**63**
Deficiency:	**0**	**(209)**	**(209)**

Schedule 2 – Utility Rate Base

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 At Existing Rates	2009 Adjustment	2009 At Revised Rates
1	**Gross Plant in Service**						
2	GPIS Beginning of Year	$ 7,540	$ 7,701	$ 7,672	$ 8,045	$ -	$ 8,045
3	Opening Adjustment	$ 2	$ -	$ -	$ -		$ -
4	GPIS End of Year	7,672	7,913	8,045	8,350	-	8,350
5	GPIS Average Mid-Year Balance	7,607	7,807	7,858	8,197	-	8,197
6							
7	CIAOC Beginning of Year	(1,041)	(1,190)	(1,159)	(1,159)	-	(1,159)
8	CIAOC End of Year	(1,159)	(1,200)	(1,159)	(1,159)	-	(1,159)
9	CIAOC Average Mid-Year Balance	(1,100)	(1,195)	(1,159)	(1,159)	-	(1,159)
10							
11	**Accumulated Depreciation**						
12	GPIS Beginning of Year	(1,783)	(1,810)	(1,865)	(2,064)	-	(2,064)
13	Opening Adjustment	-	-	-	-	-	-
14	GPIS End of Year	(1,865)	(2,010)	(2,064)	(2,273)	-	(2,273)
15	GPIS Average Mid-Year Balance	(1,824)	(1,910)	(1,965)	(2,168)	-	(2,168)
16							
17	CIAOC Beginning of Year	509	550	543	554	-	554
18	CIAOC End of Year	543	591	554	576	-	576
19	CIAOC Average Mid-Year Balance	526	571	549	565	-	565
20							
21	**Net Plant in Service, Mid-Year**	**$ 5,209**	**$ 5,272**	**$ 5,284**	**$ 5,435**	**$ -**	**$ 5,435**
22							
26	Unamortized Deferred Charges	2	85	266	264	-	264
27	Cash Working Capital	(213)	(221)	(256)	(281)	4	(277)
28	Other Working Capital	17	18	4	3	-	3
29							
30	**Utility Rate Base**	**$ 5,015**	**$ 5,154**	**$ 5,297**	**$ 5,421**	**$ 4**	**$ 5,426**

Schedule 3 – Utility Income & Earned Return

Line No.	Particulars	2007 Actual Normalized	2008 Decision	2008 Projected	2009 @ Existing Rates	Adjustment	2009 @ Revised Rates
1	**Average No. of Customers**	2,340	2,341	2,372	2,355		2,355
2							
3	**Energy Volumes (TJ)**						
4	Sales	552	589	561	554		554
5	Transportation Service	264	265	231	214		214
6	**Total Energy Volumes (TJ)**	**816**	**854**	**792**	**768**	**-**	**768**
7							
8	**Utility Revenue**						
9	Sales - Existing Rates	$ 4,678	$ 4,925	$ 5,368	$ 5,707		5,707
10	- Increase	-	210			174	174
11	Transportation - Existing Rates	235	239	250	231		231
12	- Increase	-	55			36	36
13	**Total Revenue**	**4,913**	**5,429**	**5,619**	**5,938**	**209**	**6,147**
14	Cost of Gas Sold (including Gas Lost)	3,786	4,054	4,381	4,709		4,709
15	Gross Margin	1,127	1,374	1,238	1,229	209	1,438
16	RSAM Revenue	149	-	90	-		-
17	**Adjusted Gross Margin**	**1,276**	**1,374**	**1,327**	**1,229**	**209**	**1,438**
18							
19	Operating & Maintenance Expense	701	652	637	664		664
20	Property Tax	98	125	125	158		158
21	Depreciation & Amortization Expense	142	198	218	193		193
22	Other Operating Revenue	(39)	(38)	(36)	(45)		(45)
23	**Total Utility Expenses**	**902**	**937**	**944**	**971**	**-**	**971**
24							
25	Utility Income Before Income Tax	374	437	383	258	209	467
26	Income Tax Expense	22	49	47	(2)	63	61
27							
28	**Earned Return**	**$ 352**	**$ 388**	**$ 336**	**$ 260**	**$ 146**	**$ 406**
29							
30	**Utility Rate Base**	**$ 5,015**	**$ 5,154**	**$ 5,297**	**$ 5,421**	**$ 4**	**$ 5,426**
31							
32	**Return on Rate Base**	**7.018%**	**7.533%**	**6.343%**	**4.800%**		**7.489%**

Schedule 4.1 – 2007, 2008 (Decision) Existing Revenue, Margin

Line No.	Particulars	Average # of Customers	Volume (TJ)	Ave. Bundled Rate	Revenue	Ave. Cost of Gas	Cost of Gas *	Ave. Margin	Margin
1	**2007 Actual Normalized**								
2	**Sales**								
3	Residential	1,909.0	272.2	$ 8.442	$ 2,297.9	$ 6.869	$ 1,869.8	$ 1.573	$ 428.1
4	General Service Rate 2.1	400.0	189.8	$ 8.606	$ 1,633.5	$ 6.868	$ 1,303.6	$ 1.738	329.9
5	General Service Rate 2.2	29.0	89.8	$ 8.316	$ 746.8	$ 6.865	$ 616.5	$ 1.451	130.3
6	**Total**	**2,338.0**	**551.8**		**4,678.2**		**3,789.9**		**888.3**
7									
8	General Firm T-Service	2.0	264.1	$ 0.891	235.2	$ (0.014)	(3.6)	$ 0.904	238.8
9									
10	**Total**	**2,340.0**	**815.9**		**$ 4,913.4**		**$ 3,786.3**		**$ 1,127.1**
11									
12	**2008 Decision**								
13	**Sales**								
14	Residential	1,901.0	284.9	$ 8.637	2,460.7	$ 6.867	1,956.4	$ 1.770	$ 504.3
15	General Service Rate 2.1	408.0	205.1	$ 8.886	1,822.5	$ 6.866	1,408.3	$ 2.019	414.2
16	General Service Rate 2.2	30.0	99.4	$ 8.563	851.2	$ 6.865	682.4	$ 1.698	168.8
17	**Total**	2,339.0	**589.4**		**5,134.4**		**4,047.1**		**1,087.3**
18									
19	General Firm T-Service	2.0	264.8	$ 1.112	294.6	$ 0.028	7.3	$ 1.085	287.3
20									
21	**Total**	2,341.0	**854.2**		**$ 5,429.0**		**$ 4,054.4**		**$ 1,374.6**

Schedule 4.2 – 2008 (Projected), 2009 (Forecast) Revenue, Margin

Line No.	Particulars	Average # of Customers	Volume (TJ)	Ave. Bundled Rate	Revenue	Ave. Cost of Gas	Cost of Gas *	Ave. Margin	Margin	Ave. Increase	Increase / (Decrease)	Ave. Revised Sales Rate	Revised Revenue
22													
23	**2008 Projected**												
24	**Sales**												
25	Residential	1,931.0	273.6	$ 9.544	2,611.2	$ 7.797	2,133.3	$ 1.747	$ 477.9				
26	General Service Rate 2.1	411.0	196.6	$ 9.707	1,908.4	$ 7.747	1,523.0	$ 1.961	385.4				
27	General Service Rate 2.2	28.0	90.6	$ 9.369	848.8	$ 7.757	702.8	$ 1.611	146.0				
28	**Total**	**2,370.0**	**560.8**		**5,368.5**		**4,359.1**		**1,009.4**				
29													
30	General Firm T-Service	2.0	231.1	$ 1.082	250.1	$ 0.094	21.7	$ 0.988	228.4				
31													
32	**Total**	**2,372.0**	**791.9**		**$ 5,618.6**		**$ 4,380.8**		**$ 1,237.8**				
33													
34	**2009 Forecast**												
35	**Sales**												
36	Residential	1,915.0	270.5	$ 10.257	2,774.6	$ 8.461	2,288.8	$ 1.796	$ 485.8	$ 0.306	82.7	$ 10.563	2,857.3
37	General Service Rate 2.1	411.0	195.0	$ 10.459	2,039.5	$ 8.464	1,650.4	$ 1.995	389.1	$ 0.340	66.2	$ 10.798	2,105.7
38	General Service Rate 2.2	28.0	88.4	$ 10.101	892.9	$ 8.463	748.1	$ 1.639	144.8	$ 0.279	24.7	$ 10.380	917.6
39	**Total**	**2,354.0**	**553.9**		**5,707.0**		**4,687.3**		**1,019.7**		**173.5**		**5,880.6**
40													
41	General Firm T-Service	1.0	213.9	$ 1.079	230.7	$ 0.101	21.7	$ 0.977	209.0	$ 0.166	35.6	$ 1.245	266.3
42													
43	**Total**	**2,355.0**	**767.8**		**$ 5,937.7**		**$ 4,709.0**		**$ 1,228.7**		**$ 209.1**		**$ 6,146.9**
44													
45	**Total Deficiency / (Surplus)**										**$ 209.1**		
46													
47	**% Increase / (Decrease)**										**3.52%**		

** Cost of Gas includes Unaccounted For Gas ("UAF") component.*

Schedule 5 – Income Tax Expense

Line No.	Particulars	2007 Actual Normalized	2008 Decision	2008 Projected	2009 @ Existing Rates	Adjustment	2009 @ Revised Rates
1	Earned Return	$ 352	$ 388	$ 336	$ 260	$ 146	$ 406
2	Less: Interest on Debt	(220)	(233)	(237)	(242)	(0)	(243)
3	Add: Non-Tax Deductible Expense (Net)	-	0	30	6	-	6
4	Less: Timing Differences	(89)	(49)	(25)	(27)	-	(27)
5		-	-	-	-	-	-
6	**Taxable Income after Tax**	**$ 43**	**$ 107**	**$ 103**	**$ (3)**	**$ 146**	**$ 143**
7							
8	**Taxable Income**	**$ 65**	**$ 156**	**$ 150**	**$ (5)**	**$ 209**	**$ 204**
9							
10	Permanent Current Tax Rate	33.000%	31.500%	31.000%	30.000%		30.000%
11	Surtax	1.120%	0.000%	0.000%	0.000%		0.000%
12	Income Tax Rate	34.120%	31.500%	31.000%	30.000%		30.000%
13	1 - Current Tax Rate	65.880%	68.500%	69.000%	70.000%		70.000%
14							
15	Income Tax						
16	Current	$ 22	$ 49	$ 47	$ (2)	$ 63	$ 61
17	Deferred Income Tax (Fort Nelson)	-					
18		-	-	-	-		-
19							
20	**Total Income Taxes**	**$ 22**	**$ 49**	**$ 47**	**$ (2)**	**$ 63**	**$ 61**

Schedule 6 – Capital Structure & Return on Capital

Line No.	Particulars		Amount	Capitalization %	Embedded Cost %	Cost Component
1	**2007 Actual Normalized**					
2	Unfunded Debt		$ 656	13.08%	4.250%	0.556%
3	Long Term Debt		2,603	51.91%	7.373%	3.827%
4	Common Equity		1,756	35.01%	7.525%	2.635%
5		**Total**	**$ 5,015**	**100.00%**		**7.018%**
6						
7	**2008 Decision**					
8	Unfunded Debt		$ 415	8.05%	5.000%	0.402%
9	Long Term Debt		2,935	56.94%	7.223%	4.113%
10	Common Equity		1,805	35.01%	8.620%	3.018%
11		**Total**	**$ 5,154**	**100.00%**		**7.533%**
12						
13	**2008 Projected**					
14	Unfunded Debt		$ 507	9.58%	5.000%	0.479%
15	Long Term Debt		2,935	55.41%	7.223%	4.002%
16	Common Equity		1,855	35.01%	5.319%	1.862%
17		**Total**	**$ 5,297**	**100.00%**		**6.343%**
18						
19	**2009 @ Existing Rates**					
20	Unfunded Debt		$ 404	7.46%	4.250%	0.317%
21	Long Term Debt		3,119	57.53%	7.223%	4.156%
22	Common Equity		1,898	35.01%	0.935%	0.327%
23		**Total**	**$ 5,421**	**100.00%**		**4.800%**
24						
25	**2009 @ Revised Rates**					
26	Unfunded Debt Adjusted		$ 407	7.50%	4.250%	0.319%
27	Long Term Debt		3,119	57.49%	7.223%	4.152%
28	Common Equity		1,899	35.01%	8.620%	3.018%
29		**Total**	**$ 5,426**	**100.00%**		**7.489%**

Schedule 7 – Operating and Maintenance Expense

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 Forecast
1	**RESOURCE VIEW**				
2	M&E Costs	$ 172	$ 145	$ 139	$ 145
3	COPE Costs	$ 61	$ 53	$ 51	$ 53
4	IBEW Costs	$ 242	$ 240	$ 239	$ 247
5	**Total Labour Costs**	**475**	**438**	**428**	**444**
6					
7	Vehicle Costs	52	52	52	59
8	Employee Expenses	32	33	32	33
9	Materials	23	22	22	23
10	Computer Costs	30	24	23	24
11	Fees & Administration Costs	78	63	59	62
12	Contractor Costs	161	165	163	166
13	Facilities	37	29	28	29
14	Recoveries & Revenue	(53)	(50)	(47)	(49)
15	**Total Non-Labour Costs**	**360**	**338**	**330**	**346**
16					
17	**Total Gross O&M Expenses**	**835**	**776**	**759**	**790**
18					
19	Less Capitalized Overhead	(134)	(124)	(121)	(126)
20					
21	**Total Net O&M Expenses**	**$ 701**	**$ 652**	**$ 637**	**$ 664**

Schedule 8 – Property and Sundry Taxes

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 Forecast
1	General, School & Other	$ 62	$ 88	$ 88	$ 104
2	1% in Lieu of General	36	37	37	54
3					
4	**Total Property Tax**	**$ 98**	**$ 125**	**$ 125**	**$ 158**

Schedule 9 – Depreciation and Amortization Expense

Line No.	Particulars		2007 Actual		2008 Decision		2008 Projected		2009 Forecast
1	**Depreciation Provision**								
2	Transmission	$	28	$	17	$	26	$	26
3	Distribution		132		152		139		149
4	General		17		42		35		35
5	Unclassified Plant								
6	**Total Depreciation Provision**		**176**		**211**		**199**		**210**
7									
8	Less: Amortization of CIAOC		(34)		(41)		(11)		(22)
9									
10	**Total Depreciation Expense**		**142**		**170**		**189**		**188**
11									
12	Amortization Expense		-		28		30		6
13									
14	**Total Depreciation & Amortization Expense**	**$**	**142**	**$**	**198**	**$**	**218**	**$**	**193**

Schedule 10 – Other Revenue

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 Forecast
1	Late Payment Charge	$ 22	$ 20	$ 26	$ 27
2					
3	Revenue form Service Work	17	17	10	17
4					
5	All Other	1	0	0	0
6					
7	**Total Other Revenue**	**$ 39**	**$ 38**	**$ 36**	**$ 45**

Schedule 11 – Utility Interest Expense

Line No.	Particulars	2007 Actual Normalized	2008 Decision	2008 Projected	2009 @ Existing Rates	Adjustment	2009 @ Revised Rates
1	Utility Rate Base	$ 5,015	$ 5,154	$ 5,297	$ 5,421	$ 4	$ 5,426
2							
3	Weighted average embedded cost of debt in the capital structure						
4	Long-term debt	3.827%	4.113%	4.002%	4.156%	-0.003%	4.152%
5	Unfunded debt	0.556%	0.402%	0.479%	0.317%	0.002%	0.319%
6	**Total**	**4.383%**	**4.515%**	**4.481%**	**4.473%**	**-0.001%**	**4.471%**
7							
8	**Utility Interest Expense**	**$ 220**	**$ 233**	**$ 237**	**$ 242**	**$ (0)**	**$ 243**

Schedule 12 – Permanent and Timing Differences

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 Forecast
1	**Permanent Differences**				
2	Non-tax Deductible Expenses	-	-	-	-
3	Deferred Amortization Expenses			30	6
4	**Total Permanent Differences**	**$ -**	**$ -**	**$ 30**	**$ 6**
5					
6	**Timing Differences**				
7	Depreciation Expense	$ 142	$ 170	$ 189	$ 188
8	Amortization of Debt Issue Expenses for Accounting	4	1	1	1
9	Debt Issue Costs / Discounts for Tax Purposes	(6)	-	-	-
10	Capital Cost Allowance	(163)	(167)	(162)	(168)
11	Cumulative Eligible Capital Allowance	(19)	-	-	-
12	Overheads Capitalized for Tax Purposes	(42)	(53)	(53)	(47)
13	Pension Reserve	(5)	-	-	-
14	**Total Timing Differences**	**$ (89)**	**$ (49)**	**$ (25)**	**$ (27)**

Schedule 13.1 – 2007, 2008 (Decision) Capital Cost Allowance

Line No.	Class	CCA Rate %	UCC Opening Balance	Opening Adjustments	Adjusted UCC Opening	Additions w/o OH	Overhead	Net Additions	1/2 Year Adjustment	Adjusted UCC	CCA	UCC Closing Balance
1	**2007 Actual**											
2	1	4%	$ 2,727	$ 410	$ 3,137	$ 201	$ 83	$ 284	$ (142)	$ 3,279	$ (131)	$ 3,290
3	2	6%	393	(0)	393	-	-	-	-	393	(24)	369
4	3	5%	19	-	19	-	-	-	-	19	(1)	18
5	6	10%	1	0	1	-	-	-	-	1	-	1
6	8	20%	8	-	8	-	-	-	-	8	(2)	6
7	10	30%	12	-	12	-	-	-	-	12	(4)	8
8	12	100%	-	-		-	-					-
9	13	manual	4	-	4	-	-	-	-	4	(1)	3
10	45	45%	-	1	1	-	-	-	-	1	-	1
11	49	8%	-	0	0	5	2	7	(4)	4	-	7
12	**Total**		**$ 3,164**	**$ 411**	**$ 3,576**	**$ 206**	**$ 85**	**$ 291**	**$ (145)**	**$ 3,721**	**$ (163)**	**$ 3,703**
13												
14	**2008 Decision**											
15	1	4%	$ 3,358		$ 3,358	$ 73	$ 72	$ 145	$ (73)	$ 3,430	$ (137)	$ 3,366
16	2	6%	369		369	-	-	-	-	369	(22)	347
17	3	5%	18		18	-	-	-	-	18	(1)	17
18	6	10%	2		2	-	-	-	-	2	-	2
19	8	20%	6		6	16	16	32	(16)	22	(4)	34
20	10	30%	8		8	-	-	-	-	8	(2)	6
21	12	100%				-	-					-
22	13	manual	3		3	-	-	-	-	3	(1)	2
23	45	45%	-		-	-	-	-	-	-	-	-
24	49	8%	-		-	-	-	-	-	-	-	-
25	**Total**		**$ 3,764**	**$ -**	**$ 3,764**	**$ 89**	**$ 88**	**$ 177**	**$ (88)**	**$ 3,852**	**$ (167)**	**$ 3,774**

Schedule 13.2 – 2008 (Projected), 2009 (Forecast) Capital Cost Allowance

Line No.	Class	CCA Rate %	UCC Opening Balance	Opening Adjustments	Adjusted UCC Opening	Additions w/o OH	Overhead	Net Additions	1/2 Year Adjustment	Adjusted UCC	CCA	UCC Closing Balance
27	**2008 Projected**											
28	1	4%	$ 3,290	$ (157)	$ 3,133	$ 217	$ 82	$ 299	$ (150)	$ 3,283	$ (131)	$ 3,301
29	2	6%	369	$ 0	369	-	-	-	-	369	(22)	347
30	3	5%	18	0	18	-	-	-	-	18	(1)	17
31	6	10%	1	0	1	-	-	-	-	1	-	1
32	8	20%	6	2	7	16	6	22	(11)	18	(4)	25
33	10	30%	8	4	11	-	-	-	-	11	(3)	8
34	12	100%	-	-		-	-					-
35	13	manual	3	(2)	2	-	-	-	-	2	(1)	1
37	49	8%	7	(1)	6	-	-	-	-	6	-	6
38	**Total**		**$ 3,703**	**$ (154)**	**$ 3,549**	**$ 233**	**$ 88**	**$ 321**	**$ (161)**	**$ 3,710**	**$ (162)**	**$ 3,709**
39												
40	**2009 Forecast**											
41	1	4%	$ 3,301	$ -	$ 3,301	$ 171	$ 75	$ 247	$ (123)	$ 3,425	$ (137)	$ 3,411
42	2	6%	347	-	347	-	-	-	-	347	(21)	326
43	3	5%	17	-	17	-	-	-	-	17	(1)	16
44	6	10%	1	-	1	-	-	-	-	1	-	1
45	8	20%	25	-	25	8	4	12	(6)	31	(6)	31
46	10	30%	8	-	8	-	-	-	-	8	(2)	6
47	12	100%	-	-		-	-					-
48	13	manual	1	-	1	-	-	-	-	1	(1)	(0)
50	49	8%	6	-	6	-	-	-	-	6	-	6
51	**Total**		**$ 3,709**	**$ -**	**$ 3,709**	**$ 179**	**$ 79**	**$ 258**	**$ (129)**	**$ 3,838**	**$ (168)**	**$ 3,799**

Schedule 14.1 – 2007 Gas Plant in Service

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	Overhead Capitalized	Retirements	Closing Balance
1	**2007 ACTUAL**								
2	**Transmission**								
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -	$ -	$ -	$ 9
4	Measuring & Regulating Structures	49	463-00	3	-	-	-	-	3
5	Other Structures & Improvements	7	464-00	7	-	-	-	(7)	1
6	Mains	49	465-00	716	(1)	-	-	-	714
7	Measuring & Regulating Equipment	49	467-10	75	286	5	-	-	365
8	Telemetering	49	467-20	4	-	-	-	-	4
9	Communication Equipment	49	468-00	-	-	-	-	-	-
10	**Total Transmission**			**815**	**284**	**5**	**-**	**(7)**	**1,097**
11									
12	**Distribution**								
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-	-	-	24
14	Structures & Improvements	1	472-00	230	-	5	9	-	245
15	Services	1	473-00	2,069	(20)	21	36	(4)	2,103
16	House Regulators & Meter Installation	1	474-00	586	-	23	39	(8)	640
17	Mains	1	475-00	1,807	1	25	42	-	1,875
18	Compressed Natural Gas	8	476-00	-	-	-	-	-	-
19	Measuring & Regulating Equipment	1	477-10/477-30	1,187	(264)	6	10	(10)	930
20	Telemetering	1	477-20	-	-	-	-	-	-
21	Meters	1	478-00	38	-	-	-	(1)	37
22	**Total Distribution**			**5,941**	**(282)**	**81**	**136**	**(23)**	**5,853**
23									
24	**General Plant**								
25	Land	land	480-00	1	-	-	-	-	1
26	Frame Structures & Improvements	1	482-00	234	-	2	-	-	236
27	Office Furniture & Equipment		483-00						
28	Computers - Hardware	45	483-10	182	-	-	-	-	182
29	Computers - Software (non-infrastructure)	12	483-20	154	-	-	-	(52)	101
30	Computers - Software (infrastructure/custom)	12	483-20	35	-	-	-	-	35
31	Office Equipment	8	483-30	41	-	-	-	-	41
32	Furniture	8	483-40	-	-	-	-	-	-
33	Transportation Equipment	10	484-00	11	-	-	-	-	11
34	Heavy Work Equipment	38	485-10/485-20	3	-	-	-	-	3
35	Small Tools & Equipment	8	486-00	93	-	-	-	(8)	85
36	Communication Equipment								
37	Telephone	8	488-10	25	-	-	-	-	25
38	Radios	8	488-20	5	-	-	-	(3)	2
39	**Total General Plant**			**784**		**2**	**-**	**(64)**	**722**
40									
41	**Total**			**$ 7,540**	**$ 2**	**$ 88**	**$ 136**	**$ (94)**	**$ 7,672**

Schedule 14.2 – 2008 (Decision) Gas Plant in Service

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	Overhead Capitalized	Retirements	Closing Balance
1	**2008 Decision**								
2	**Transmission**								
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -	$ -	$ -	$ 9
4	Measuring & Regulating Structures	49	463-00	3	-	-	-	-	3
5	Other Structures & Improvements	7	464-00	7	-	-	-	-	7
6	Mains	49	465-00	715	-	-	-	-	715
7	Measuring & Regulating Equipment	49	467-10	75	-	-	-	-	75
8	Telemetering	49	467-20	4	-	-	-	-	4
9	Communication Equipment	49	468-00	-	-	-	-	-	-
10	**Total Transmission**			**814**	**-**	**-**	**-**	**-**	**814**
11									
12	**Distribution**								
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-	-	-	24
14	Structures & Improvements	1	472-00	230	-	-	-	-	230
15	Services	1	473-00	2,198	-	28	68	(4)	2,290
16	House Regulators & Meter Installation	1	474-00	618	-	7	16	(0)	641
17	Mains	1	475-00	1,873	-	24	57	(2)	1,952
18	Compressed Natural Gas	8	476-00	-	-	-	-	-	-
19	Measuring & Regulating Equipment	1	477-10/477-30	1,288	-	-	-	-	1,288
20	Telemetering	1	477-20	14	-	-	-	-	14
21	Meters	1	478-00	51	-	4	-	(0)	56
22	**Total Distribution**			**6,297**	**-**	**63**	**141**	**(7)**	**6,494**
23									
24	**General Plant**								
25	Land	land	480-00	1	-	-	-	-	1
26	Frame Structures & Improvements	1	482-00	234	-	-	-	-	234
27	Office Furniture & Equipment		483-00						
28	Computers - Hardware	45	483-10	(7)	-	-	-	-	(7)
29	Computers - Software (non-infrastructure)	12	483-20	154	-	-	-	-	154
30	Computers - Software (infrastructure/custom)	12	483-20	35	-	-	-	-	35
31	Office Equipment	8	483-30	41	-	-	-	-	41
32	Furniture	8	483-40	-	-	-	-	-	-
33	Transportation Equipment	10	484-00	11	-	-	-	-	11
34	Heavy Work Equipment	38	485-10/485-20	3	-	-	-	-	3
35	Small Tools & Equipment	8	486-00	93	-	16	-	-	109
36	Communication Equipment								
37	Telephone	8	488-10	25	-	-	-	-	25
38	Radios	8	488-20	(1)	-	-	-	-	(1)
39	**Total General Plant**			**589**		**16**	**-**	**-**	**605**
40									
41	**Total**			**$ 7,701**	**$ -**	**$ 79**	**$ 141**	**$ (7)**	**$ 7,913**

Schedule 14.3 – 2008 (Projected) Gas Plant in Service

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	Overhead Capitalized	Retirements	Closing Balance
1	**2008 PROJECTED**								
2	**Transmission**								
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -	$ -	$ -	$ 9
4	Measuring & Regulating Structures	49	463-00	3	-	-	-	-	3
5	Other Structures & Improvements	7	464-00	1	-	-	-	-	1
6	Mains	49	465-00	714	-	-	-	-	714
7	Measuring & Regulating Equipment	49	467-10	365	-	-	-	-	365
8	Telemetering	49	467-20	4	-	-	-	-	4
9	Communication Equipment	49	468-00	-	-	-	-	-	-
10	**Total Transmission**			**1,097**	**-**	**-**	**-**	**-**	**1,097**
11									
12	**Distribution**								
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-	-	-	24
14	Structures & Improvements	1	472-00	245	-	-	-	-	245
15	Services	1	473-00	2,103	-	28	19	-	2,149
16	House Regulators & Meter Installation	1	474-00	640	-	7	4	-	651
17	Mains	1	475-00	1,875	-	31	21	-	1,927
18	Compressed Natural Gas	8	476-00	-	-	-	-	-	-
19	Measuring & Regulating Equipment	1	477-10/477-30	930	-	147	98	-	1,175
20	Telemetering	1	477-20	-	-	-	-	-	-
21	Meters	1	478-00	37	-	4	-	-	41
22	**Total Distribution**			**5,853**	**-**	**217**	**141**	**-**	**6,211**
23									
24	**General Plant**								
25	Land	land	480-00	1	-	-	-	-	1
26	Frame Structures & Improvements	1	482-00	236	-	-	-	-	236
27	Office Furniture & Equipment		483-00						
28	Computers - Hardware	45	483-10	182	-	-	-	-	182
29	Computers - Software (non-infrastructure)	12	483-20	101	-	-	-	-	101
30	Computers - Software (infrastructure/custom)	12	483-20	35	-	-	-	-	35
31	Office Equipment	8	483-30	41	-	-	-	-	41
32	Furniture	8	483-40	-	-	-	-	-	-
33	Transportation Equipment	10	484-00	11	-	-	-	-	11
34	Heavy Work Equipment	38	485-10/485-20	3	-	-	-	-	3
35	Small Tools & Equipment	8	486-00	85	-	16	-	(1)	100
36	Communication Equipment								
37	Telephone	8	488-10	25	-	-	-	-	25
38	Radios	8	488-20	2	-	-	-	-	2
39	**Total General Plant**			**722**		**16**	**-**	**(1)**	**737**
40									
41	**Total**			**$ 7,672**	**$ -**	**$ 233**	**$ 141**	**$ (1)**	**$ 8,045**

Schedule 14.4 – 2009 Gas Plant in Service

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	Overhead Capitalized	Retirements	Closing Balance
1	**2009 FORECAST**								
2	**Transmission**								
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -	$ -	$ -	$ 9
4	Measuring & Regulating Structures	49	463-00	3	-	-	-	-	3
5	Other Structures & Improvements	7	464-00	1	-	-	-	-	1
6	Mains	49	465-00	714	-	-	-	-	714
7	Measuring & Regulating Equipment	49	467-10	365	-	-	-	-	365
8	Telemetering	49	467-20	4	-	-	-	-	4
9	Communication Equipment	49	468-00	-	-	-	-	-	-
10	**Total Transmission**			**1,097**	**-**	**-**	**-**	**-**	**1,097**
11									
12	**Distribution**								
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-	-	-	24
14	Structures & Improvements	1	472-00	245	-	-	-	-	245
15	Services	1	473-00	2,149	-	35	30	-	2,214
16	House Regulators & Meter Installation	1	474-00	651	-	4	4	-	659
17	Mains	1	475-00	1,927	-	59	50	-	2,036
18	Compressed Natural Gas	8	476-00	-	-	-	-	-	-
19	Measuring & Regulating Equipment	1	477-10/477-30	1,175	-	50	43	-	1,267
20	Telemetering	1	477-20	-	-	-	-	-	-
21	Meters	1	478-00	41	-	3	-	-	44
22	**Total Distribution**			**6,211**	**-**	**151**	**126**	**-**	**6,488**
23									
24	**General Plant**								
25	Land	land	480-00	1	-	-	-	-	1
26	Frame Structures & Improvements	1	482-00	236	-	20	-	-	256
27	Office Furniture & Equipment		483-00						
28	Computers - Hardware	45	483-10	182	-	-	-	-	182
29	Computers - Software (non-infrastructure)	12	483-20	101	-	-	-	-	101
30	Computers - Software (infrastructure/custom)	12	483-20	35	-	-	-	-	35
31	Office Equipment	8	483-30	41	-	-	-	-	41
32	Furniture	8	483-40	-	-	-	-	-	-
33	Transportation Equipment	10	484-00	11	-	-	-	-	11
34	Heavy Work Equipment	38	485-10/485-20	3	-	-	-	-	3
35	Small Tools & Equipment	8	486-00	100	-	8	-	(1)	108
36	Communication Equipment								
37	Telephone	8	488-10	25	-	-	-	-	25
38	Radios	8	488-20	2	-	-	-	-	2
39	**Total General Plant**			**737**		**28**	**-**	**(1)**	**764**
40									
41	**Total**			**$ 8,045**	**$ -**	**$ 179**	**$ 126**	**$ (1)**	**$ 8,350**

Schedule 15.1 – 2007 Accumulated Depreciation

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance
1	**2007 ACTUAL**											
2	**Transmission**											
3	Land / Land Rights	460-00/461-00	N / A	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Measuring & Regulating Structures	463-00	3.00%	3	$ -	$ -	$ 0	-	-	-	-	$ 0.1
5	Other Structures & Improvements	464-00	3.00%	7	$ 2	$ -	$ 0	2	(7)	-	-	$ (1.8)
6	Mains	465-00	2.00%	716	$ 2	$ -	$ 12	(1)	-	-	-	$ 12.5
7	Measuring & Regulating Equipment	467-10	3.00%	75	$ 28	$ -	$ 4	10	-	-	-	$ 41.4
8	Telemetering	467-20	10.00%	4	$ (3)	$ -	$ 1	-	-	-	-	$ (2.9)
9	Communication Equipment	468-00	10.00%	-	$ -	$ -	$ -	-	-	-	-	$ -
10	**Total Transmission**			**815**	**28**	**-**	**16**	**12**	**(7)**	**-**	**-**	**49.4**
11												
12	**Distribution**											
13	Land / Land Rights	470-00/471-00	N / A	24	-	-	-	-	-	-	-	-
14	Structures & Improvements	472-00	3.00%	230	32	-	6	-	-	-	-	38
15	Services	473-00	2.00%	2,069	646	-	37	3	(4)	-	-	682
16	House Regulators & Meter Installation	474-00	3.57%	586	166	-	19	6	(8)	-	-	182
17	Mains	475-00	2.00%	1,807	342	-	32	0	-	-	-	375
18	Compressed Natural Gas	476-00	6.67%	-	(97)	-	-	-	-	-	-	(97)
19	Measuring & Regulating Equipment	477-10/477-30	3.00%	1,187	178	-	29	(2)	(10)	-	-	195
20	Telemetering	477-20	10.00%	-	9	-	1	-	-	-	-	10
21	Meters	478-00	3.57%	38	9	-	1	0	(1)	-	-	10
22	**Total Distribution**			**5,941**	**1,286**	**-**	**125**	**7**	**(23)**	**-**	**-**	**1,394**
23												
24	**General Plant**											
25	Land	480-00	N / A	1	-	-	-	-	-	-	-	-
26	Frame Structures & Improvements	482-00	3.00%	234	158	-	7	-	-	-	-	165
27	Office Furniture & Equipment	483-00					-		-			
28	Computers - Hardware	483-10	20.00%	182	229	-	-	(0)	-	-	-	229
29	Computers - Software (infrastructure)	483-20	12.50%	154	60	-	7	(3)	(52)	-	-	12
30	Computers - Software (non-infrastructure)	483-20	20.00%	35	-	-	-	-	-	-	-	-
31	Office Equipment	483-30	5.00%	41	18	-	1	-	-	-	-	19
32	Furniture	483-40	5.00%	-	-	-	-	-	-	-	-	-
33	Transportation Equipment	484-00	15.00%	11	(26)	-	-	-	-	-	-	(26)
34	Heavy Work Equipment	485-10/485-20	5.00%	3	(52)	-	-	-	-	-	-	(52)
35	Small Tools & Equipment	486-00	5.00%	93	50	-	4	(0)	(8)	-	-	45
36	Communication Equipment						-		-			
37	Telephone	488-10	5.00%	25	18	-	1	-	-	-	-	19
38	Radios	488-20	10.00%	5	14	-	0	(0)	(3)	-	-	11
39	**Total General Plant**			**784**	**469**	**-**	**21**	**(4)**	**(64)**	**-**	**-**	**422**
40												
41	**Total**			**$ 7,540**	**$ 1,783**	**$ -**	**162**	**$ 15**	**$ (94)**	**$ -**	**$ -**	**$ 1,865**

Schedule 15.2 – 2008 (Decision) Accumulated Depreciation

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance
1	**2008 DECISION**											
2	**Transmission**											
3	Land / Land Rights	460-00/461-00	N / A	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Measuring & Regulating Structures	463-00	3.00%	3	1	-	0	-	-	-	-	1
5	Other Structures & Improvements	464-00	3.00%	7	2	-	0	-	-	-	-	2
6	Mains	465-00	2.00%	715	17	-	14	-	-	-	-	31
7	Measuring & Regulating Equipment	467-10	3.00%	75	29	-	2	-	-	-	-	31
8	Telemetering	467-20	10.00%	4	(3)	-	0	-	-	-	-	(3)
9	Communication Equipment	468-00	10.00%	-	-	-	-	-	-	-	-	-
10	**Total Transmission**			**814**	**45**	**-**	**17**	**-**	**-**	**-**	**-**	**62**
11												
12	**Distribution**											
13	Land / Land Rights	470-00/471-00	N / A	24	-	-	-	-	-	-	-	-
14	Structures & Improvements	472-00	3.00%	230	40	-	7	-	-	-	-	47
15	Services	473-00	2.00%	2,198	677	-	44	-	(4)	-	(4)	712
16	House Regulators & Meter Installation	474-00	3.57%	618	186	-	22	-	(0)	-	(0)	207
17	Mains	475-00	2.00%	1,873	374	-	37	-	(2)	-	-	409
18	Compressed Natural Gas	476-00	6.67%	-	-	-	-	-	-	-	-	-
19	Measuring & Regulating Equipment	477-10/477-30	3.00%	1,288	205	-	39	-	-	-	-	244
20	Telemetering	477-20	10.00%	14	10	-	1	-	-	-	-	12
21	Meters	478-00	3.57%	51	11	-	2	-	(0)	-	-	12
22	**Total Distribution**			**6,297**	**1,503**	**-**	**152**	**-**	**(7)**	**-**	**(4)**	**1,644**
23												
24	**General Plant**											
25	Land	480-00	N / A	1	-	-	-	-	-	-	-	-
26	Structures & Improvements	482-00	3.00%	234	159	-	7	-	-	-	-	166
27	Office Furniture & Equipment	483-00										
28	Computers - Hardware	483-10	20.00%	(7)	1	-	(1)	-	-	-	-	(1)
29	Computers - Software (non-infrastructure)	483-20	12.50%	154	79	-	19	-	-	-	-	98
30	Computers - Software (infrastructure/custom)	483-20	20.00%	35	11	-	7	-	-	-	-	18
31	Office Equipment	483-30	5.00%	41	21	-	2	-	-	-	-	23
32	Furniture	483-40	5.00%	-	(0)	-	-	-	-	-	-	(0)
33	Transportation Equipment	484-00	15.00%	11	(24)	-	2	-	-	-	-	(23)
34	Heavy Work Equipment	485-10/485-20	5.00%	3	(57)	-	0	-	-	-	-	(57)
35	Small Tools & Equipment	486-00	5.00%	93	54	-	5	-	-	-	-	59
36	Communication Equipment											
37	Telephone	488-10	5.00%	25	18	-	1	-	-	-	-	20
38	Radio	488-20	10.00%	(1)	1	-	(0)	-	-	-	-	1
39	**Total General Plant**			**589**	**262**	**-**	**42**	**-**	**-**	**-**	**-**	**304**
40												
41	**Total**			**$ 7,701**	**$ 1,810**	**$ -**	**$ 211**	**$ -**	**$ (7)**	**$ -**	**$ (4)**	**$ 2,010**

Schedule 15.3 – 2008 (Projected) Accumulated Depreciation

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance
1	**2008 PROJECTED**											
2	**Transmission**											
3	Land / Land Rights	460-00/461-00	N / A	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Measuring & Regulating Structures	463-00	3.00%	3	0	-	0	-	-	-	-	0
5	Other Structures & Improvements	464-00	3.00%	1	(2)	-	0	-	-	-	-	(2)
6	Mains	465-00	2.00%	714	13	-	14	-	-	-	-	27
7	Measuring & Regulating Equipment	467-10	3.00%	365	41	-	11	-	-	-	-	52
8	Telemetering	467-20	10.00%	4	(3)	-	0	-	-	-	-	(2)
9	Communication Equipment	468-00	10.00%	-	-	-	-	-	-	-	-	-
10	**Total Transmission**			**1,097**	**49**	**-**	**26**	**-**	**-**	**-**	**-**	**75**
11												
12	**Distribution**											
13	Land / Land Rights	470-00/471-00	N / A	24	-	-	-	-	-	-	-	-
14	Structures & Improvements	472-00	3.00%	245	38	-	7	-	-	-	-	45
15	Services	473-00	2.00%	2,103	682	-	42	-	-	-	-	724
16	House Regulators & Meter Installation	474-00	3.57%	640	182	-	23	-	-	-	-	205
17	Mains	475-00	2.00%	1,875	375	-	37	-	-	-	-	412
18	Compressed Natural Gas	476-00	6.67%	-	(97)	-	-	-	-	-	-	(97)
19	Measuring & Regulating Equipment	477-10/477-30	3.00%	930	195	-	28	-	-	-	-	223
20	Telemetering	477-20	10.00%	-	10	-	-	-	-	-	-	10
21	Meters	478-00	3.57%	37	10	-	1	-	-	-	-	11
22	**Total Distribution**			**5,853**	**1,394**	**-**	**139**	**-**	**-**	**-**	**-**	**1,533**
23												
24	**General Plant**											
25	Land	480-00	N / A	1	-	-	-	-	-	-	-	-
26	Frame Structures & Improvements	482-00	3.00%	236	165	-	7	-	-	-	-	172
27	Office Furniture & Equipment	483-00				-		-		-	-	
28	Computers - Hardware	483-10	20.00%	182	229	-	-	-	-	-	-	229
29	Computers - Software (infrastructure)	483-20	12.50%	101	12	-	13	-	-	-	-	24
30	Computers - Software (non-infrastructure)	483-20	20.00%	35	-	-	7	-	-	-	-	7
31	Office Equipment	483-30	5.00%	41	19	-	2	-	-	-	-	21
32	Furniture	483-40	5.00%	-	-	-	-	-	-	-	-	-
33	Transportation Equipment	484-00	15.00%	11	(26)	-	-	-	-	-	-	(26)
34	Heavy Work Equipment	485-10/485-20	5.00%	3	(52)	-	0	-	-	-	-	(52)
35	Small Tools & Equipment	486-00	5.00%	85	45	-	4	-	(1)	-	-	48
36	Communication Equipment					-		-		-	-	
37	Telephone	488-10	5.00%	25	19	-	1	-	-	-	-	20
38	Radios	488-20	10.00%	2	11	-	0	-	-	-	-	11
39	**Total General Plant**			**722**	**422**	**-**	**35**	**-**	**(1)**	**-**	**-**	**456**
40												
41	**Total**			**$ 7,672**	**$ 1,865**	**$ -**	**$ 199**	**$ -**	**$ (1)**	**$ -**	**$ -**	**$ 2,064**

Schedule 15.4 – 2009 Accumulated Depreciation

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance
1	**2009 FORECAST**											
2	**Transmission**											
3	Land / Land Rights	460-00/461-00	N / A	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Measuring & Regulating Structures	463-00	3.00%	3	0	-	0	-	-	-	-	0
5	Other Structures & Improvements	464-00	3.00%	1	(2)	-	0	-	-	-	-	(2)
6	Mains	465-00	2.00%	714	27	-	14	-	-	-	-	41
7	Measuring & Regulating Equipment	467-10	3.00%	365	52	-	11	-	-	-	-	63
8	Telemetering	467-20	10.00%	4	(2)	-	0	-	-	-	-	(2)
9	Communication Equipment	468-00	10.00%	-	-	-	-	-	-	-	-	-
10	**Total Transmission**			**1,097**	**75**	**-**	**26**	**-**	**-**	**-**	**-**	**101**
11												
12	**Distribution**											
13	Land / Land Rights	470-00/471-00	N / A	24	-	-	-	-	-	-	-	-
14	Structures & Improvements	472-00	3.00%	245	45	-	7	-	-	-	-	53
15	Services	473-00	2.00%	2,149	724	-	43	-	-	-	-	767
16	House Regulators & Meter Installation	474-00	3.57%	651	205	-	23	-	-	-	-	228
17	Mains	475-00	2.00%	1,927	412	-	39	-	-	-	-	451
18	Compressed Natural Gas	476-00	6.67%	-	(97)	-	-	-	-	-	-	(97)
19	Measuring & Regulating Equipment	477-10/477-30	3.00%	1,175	223	-	35	-	-	-	-	258
20	Telemetering	477-20	10.00%	-	10	-	-	-	-	-	-	10
21	Meters	478-00	3.57%	41	11	-	1	-	-	-	-	13
22	**Total Distribution**			**6,211**	**1,533**	**-**	**149**	**-**	**-**	**-**	**-**	**1,682**
23												
24	**General Plant**											
25	Land	480-00	N / A	1	-	-	-	-	-	-	-	-
26	Frame Structures & Improvements	482-00	3.00%	236	172	-	7	-	-	-	-	179
27	Office Furniture & Equipment	483-00				-		-		-	-	
28	Computers - Hardware	483-10	20.00%	182	229	-	-	-	-	-	-	229
29	Computers - Software (infrastructure)	483-20	12.50%	101	24	-	13	-	-	-	-	37
30	Computers - Software (non-infrastructure)	483-20	20.00%	35	7	-	7	-	-	-	-	14
31	Office Equipment	483-30	5.00%	41	21	-	2	-	-	-	-	23
32	Furniture	483-40	5.00%	-	-	-	-	-	-	-	-	-
33	Transportation Equipment	484-00	15.00%	11	(26)	-	-	-	-	-	-	(26)
34	Heavy Work Equipment	485-10/485-20	5.00%	3	(52)	-	0	-	-	-	-	(52)
35	Small Tools & Equipment	486-00	5.00%	100	48	-	5	-	(1)	-	-	53
36	Communication Equipment					-		-		-	-	
37	Telephone	488-10	5.00%	25	20	-	1	-	-	-	-	22
38	Radios	488-20	10.00%	2	11	-	0	-	-	-	-	11
39	**Total General Plant**			**737**	**456**	**-**	**35**	**-**	**(1)**	**-**	**-**	**490**
40												
41	**Total**			**$ 8,045**	**$ 2,064**	**$ -**	**$ 210**	**$ -**	**$ (1)**	**$ -**	**$ -**	**$ 2,273**

Schedule 16.1 – 2007, 2008 (Decision) Contributions in Aid of Construction

Line No.	Particulars	Opening Balance	Additions	Retirements	Ending Balance
1	**2007 Actual**				
2	Gross Contributions				
3	DSEP / GEAP	$ 248	$ -	$ -	$ 248
4	Computer Software Tax Credit	156	-	-	156
5	Other	637	118	-	755
6	Total Gross Contributions	1,041	118	-	1,159
7					
8	Accumulated Amortization				
9	Computer Software Tax Savings	(127)	(19)	-	(146)
10	Other	(382)	(16)	-	(398)
11	Total Accumulated Amortization	(509)	(34)	-	(543)
12					
13	**Total 2007 Actual Net CIAOC**	**$ 532**	**$ 84**	**$ -**	**$ 616**
14					
15	**2008 Decision**				
16	Gross Contributions				
17	DSEP / GEAP	$ 248			$ 248
18	Computer Software Tax Credit	156	-		156
19	Other	786	10		796
20	Total Gross Contributions	1,190	10	-	1,200
21					
22	Accumulated Amortization				
23	Computer Software Tax Savings	(147)	(21)		(168)
24	Other	(403)	(20)		(423)
25	Total Accumulated Amortization	(550)	(41)	-	(591)
26					
27	**Total 2008 Decision Net CIAOC**	**$ 640**	**$ (31)**	**$ -**	**$ 609**

Schedule 16.2 – 2008 (Projected), 2009 (Forecast) Contributions in Aid of Construction

Line No.	Particulars	Opening Balance	Additions	Retirements	Ending Balance
28					
29	**2008 Projected**				
30	Gross Contributions				
31	DSEP / GEAP	$ 248	$ -	$ -	$ 248
32	Computer Software Tax Credit	156	-	-	156
33	Other	755	-	-	755
34	Total Gross Contributions	1,159	-	-	1,159
35					
36	Accumulated Amortization				
37	Computer Software Tax Savings	(146)	(11)	-	(156)
38	Other	(398)	-	-	(398)
39	Total Accumulated Amortization	(543)	(11)	-	(554)
40					
41	**Total 2008 Projected Net CIAOC**	**$ 616**	**$ (11)**	**$ -**	**$ 605**
42					
43	**2009 Forecast**				
44	Gross Contributions				
45	DSEP / GEAP	$ 248	$ -	$ -	$ 248
46	Computer Software Tax Credit	156	-	-	156
47	Other	755	-	-	755
48	Total Gross Contributions	1,159	-	-	1,159
49					
50	Accumulated Amortization				
51	Computer Software Tax Savings	(156)	-	-	(156)
52	Other	(398)	(22)	-	(420)
53	Total Accumulated Amortization	(554)	(22)	-	(576)
54					
55	**Total 2009 Forecast Net CIAOC**	**$ 605**	**$ (22)**	**$ -**	**$ 583**

Schedule 17.1 – 2007 (Actual), 2008 (Decision) Unamortized Deferred Charges

Line No.	Particulars	Opening Balance	Gross Additions	Less Taxes	Net Additions	Amortization Expense	Amortization Other / Int.	Closing Balance	Mid-Year Average
1	**<u>2007 ACTUAL</u>**								
2	Deferred Interest	$ (4)	$ 13	$ (4)	$ 9	$ -	$ -	$ 5	$ 1
3	Property Tax Deferral	$ 14	$ 28	$ (9)	$ 19	$ -	$ -	$ 33	$ 24
4	RSAM	185	149	(49)	100	-		285	235
5	RSAM Rate Rider Recovery	(22)	(60)	20	(40)			(62)	(42)
6	RSAM, Net	163	89	(29)	60	-	-	223	193
7									
8	RSAM Interest	3	5	(2)	3	-	-	6	4
9									
10	GCRA	(327)	321	(106)	215	-	-	(112)	(220)
11	GCRA Rate Rider Recovery	-			-				-
12	GCRA, Net	(327)	321	(106)	215	-		(112)	(220)
13									
14	**Total 2007 ACTUAL**	**$ (151)**	**$ 456**	**$ (150)**	**$ 305**	**$ -**		**$ 154**	**$ 2**
15									
16	**<u>2008 Decision</u>**								
17	Deferred Interest	$ (1)	$ -	$ -	$ -	$ 1		$ -	$ (1)
18	Property Tax Deferral	$ 29	$ -	$ -	$ -	$ (29)		$ -	$ 15
19	RSAM	262	-	-	-			262	262
20	RSAM Rate Rider Recovery	(64)	(99)	31	(68)			(132)	(98)
21	RSAM, Net	198	(99)	31	(68)			130	164
22									
23	Income Tax Change Deferral								
24									
25	RSAM Interest	5	-	-	-			5	5
26									
27	GCRA	(99)	-	-	-			(99)	(99)
28	GCRA Rate Rider Recovery	-	-		-				-
29	GCRA, Net	(99)	-	-	-			(99)	(99)
30									
31	**Total 2008 Decision**	**$ 132**	**$ (99)**	**$ 31**	**$ (68)**	**$ (28)**		**$ 37**	**$ 85**

Schedule 17.2 – 2008 (Projected), 2009 (Forecast) Unamortized Deferred Charges

Line No.	Particulars	Opening Balance	Gross Additions	Less Taxes	Net Additions	Amortization Expense	Amortization Other / Int.	Closing Balance	Mid-Year Average
32									
33	**2008 Projected**								
34	Deferred Interest	$ 5	$ (21)	$ 7	$ (14)	$ -	$ -	$ (9)	$ (2)
35	Property Tax Deferral	33	$ 17	$ (5)	$ 12	$ (30)	$ -	$ 15	$ 24
36	RSAM	285	90	(28)	62	-		347	316
37	RSAM Rate Rider Recovery	(62)	(87)	27	(60)			(122)	(92)
38	RSAM, Net	223	3	(1)	2	-	-	224	223
39									
40	Income Tax Change Deferral								
41									
42	RSAM Interest	6	(1)	0	(0)	-	-	6	6
43									
44	GCRA	(112)	368	(114)	254	-	-	142	15
45	GCRA Rate Rider Recovery	-	-		-				-
46	GCRA, Net	(112)	368	(114)	254			142	15
47									
48	**Total 2008 Projected**	**$ 154**	**$ 366**	**$ (114)**	**$ 253**	**$ (30)**		**$ 377**	**$ 266**
49									
50	**2009 Forecast**								
51	Deferred Interest	$ (9)	$ -	$ -	$ -	$ 9	$ -	$ -	$ (5)
52	Property Tax Deferral	15	$ -	$ -	$ -	$ (15)	$ -	$ -	$ 7
53	RSAM	347	-	-	-	-		347	347
54	RSAM Rate Rider Recovery	(122)	(109)	33	(77)			(199)	(161)
55	RSAM, Net	224	(109)	33	(77)	-	-	148	186
56									
57	Income Tax Change Deferral								
58									
59	RSAM Interest	6	(0)	0	(0)	-	2	4	5
60									
61	GCRA	142	(203)	61	(142)	-	-	-	71
62	GCRA Rate Rider Recovery	-	-		-				-
63	GCRA, Net	142	(203)	61	(142)			-	71
64									
65	**Total 2009 Forecast**	**$ 377**	**$ (312)**	**$ 94**	**$ (219)**	**$ (6)**		**$ 151**	**$ 264**

Schedule 18.1 – Cash Working Capital

Line No.	Particulars	2007 Actual Normalized	2008 Decision	2008 Projected	2009 At Existing Rates	2009 Adjustment	2009 At Revised Rates
1							
2	Revenue Lead Days	35.2	35.3	35.1	35.1	0.1	35.1
3	Expense Lag Days	(36.8)	(36.9)	(37.6)	(38.1)	0.2	(37.9)
4	**Net (Lead) / Lag Days**	**(1.6)**	**(1.6)**	**(2.5)**	**(3.0)**	**0.3**	**(2.8)**
5							
6	Cash Required for Operating Expenses	$ (21)	$ (24)	$ (40)	$ (55)	$ 4	$ (51)
7	Minimum Cash Balance / Customer Deposits	(162)	(170)	(183)	(192)	-	(192)
8							
9	Less Reserve for Bad Debts	(26)	(24)	(19)	(20)	-	(19.9)
10	Withholdings from Employees	(4)	(3)	(14)	(15)	-	(14.6)
11							
12	**Total Cash Working Capital**	**$ (213)**	**$ (221)**	**$ (256)**	**$ (281)**	**$ 4**	**(277)**

Schedule 18.2a – 2007 (Actual), 2008 (Decision), 2008 (Projected) Lead Time from Date of Payment to Receipt of Cash

Line No.	Particulars	Revenue	Lead Days	Dollar Days
1	**2007 Actual Normalized**			
2	Residential & Commercial	$ 4,678	34.6	$ 161,866
3	Small Industrial	235	47.2	11,101
4	**Total Sales / T-Service**	**4,913**	**35.2**	**172,967**
5				
6	**Other Revenue**			
7	Late Payment Charge	22	26.7	574
8	All Other	1	35.3	18
9	Revenue from Service Work	17	41.9	708
10	**Total**	**$ 4,952**	**35.2**	**$ 174,267**
11				
12	**2008 Decision**			
13	Residential & Commercial	$ 5,134	34.6	$ 177,650
14	Small Industrial	295	47.2	13,904
15	**Total Sales / T-Service**	**5,429**	**35.3**	**191,554**
16				
17	**Other Revenue**			
18	Late Payment Charge	20	26.7	545
19	All Other	0	35.3	14
20	Revenue from Service Work	17	41.9	700
21	**Total**	**$ 5,466**	**35.3**	**$ 192,813**
22				
23	**2008 Projected**			
24	Residential & Commercial	$ 5,368	34.6	$ 185,749
25	Small Industrial	250	47.2	11,805
26	**Total Sales / T-Service**	**5,619**	**35.2**	**197,554**
27				
28	**Other Revenue**			
29	Late Payment Charge	26	26.7	681
30	All Other	0	35.3	14
31	Revenue from Service Work	10	41.9	432
32	**Total**	**$ 5,655**	**35.1**	**$ 198,681**

Schedule 18.2b – 2009 Lead Time from Date of Payment to Receipt of Cash

Line No.	Particulars		Revenue	Lead Days		Dollar Days
1	**2009 Forecast at Existing Rates**					
2	Residential & Commercial	$	5,707	34.6	$	197,464
3	Small Industrial		231	47.2		10,889
4	**Total Sales / T-Service**		5,938	35.1		**208,353**
5						
6	**Other Revenue**					
7	Late Payment Charge		27	26.7		724
8	All Other		0	35.3		14
9	Revenue from Service Work		17	41.9		716
10	**Total**	**$**	**5,982**	**35.1**	**$**	**209,807**
11						
12	**2009 Forecast at Revised Rates**					
13	Residential & Commercial	$	5,881	34.6	$	203,469
14	Small Industrial		266	47.2		12,568
15	**Total Sales / T-Service**		**6,147**	**35.1**		**216,037**
16						
17	**Other Revenue**					
18	Late Payment Charge		27	26.7		724
19	All Other		0	35.3		14
20	Revenue from Service Work		17	41.9		716
21	**Total**	**$**	**6,191**	**35.1**	**$**	**217,491**

Schedule 18.3a – 2007 (Actual), 2008 (Decision), 2008 (Projected) Lag Time in Payment of Expenses

Line No.	Particulars	Expense	Lag Days	Dollar Days
1	**2007 Actual Normalized**			
2	Operating & Maintenance Expense	$ 703	19.3	$ 13,569
3	Cost of Gas	3,786	40.7	154,102
4				
5	Taxes other than income tax			
6	Property Taxes	98	4.0	392
7	Goods & Service Tax (GST)	51	41.7	2,127
8	S. S. Tax	165	43.8	7,227
9	Income Tax	22	15.2	334
10	**Total Expense**	**$ 4,825**	**36.8**	**$ 177,751**
11				
12	**2008 Decision**			
13	Operating & Maintenance Expense	$ 739	19.3	$ 14,269
14	Cost of Gas	4,054	40.7	165,014
15				
16	Taxes other than income			
17	Property Taxes	125	4.0	500
18	Goods & Service Tax	260	41.7	10,845
19	S. S. Tax	199	43.8	8,701
20	Carbon Tax			
21	Income Tax	49	15.2	747
22	**Total Expense**	**$ 5,427**	**36.9**	**$ 200,077**
23				
24	**2008 Projected**			
25	Operating & Maintenance Expense	$ 637	19.3	$ 12,297
26	Cost of Gas	4,381	40.7	178,299
27				
28	Taxes other than income			
29	Property Taxes	125	4.0	500
30	Goods & Service Tax	283	41.7	11,790
31	S. S. Tax	213	43.8	9,331
32	Carbon Tax	160	43.8	6,990
33	Income Tax	47	15.2	714
34	**Total Expense**	**$ 5,845**	**37.6**	**$ 219,922**

Schedule 18.3b – 2009 (Forecast) Lag Time in Payment of Expenses

Line No.	Particulars	Expense	Lag Days	Dollar Days
1	**2009 Forecast at Existing Rates**			
2	Operating & Maintenance Expense	$ 664	19.3	$ 12,807
3	Cost of Gas	4,709	40.7	191,656
4				
5	Taxes other than income			
6	Property Taxes	158	4.0	633
7	Goods & Service Tax	299	41.7	12,473
8	S. S. Tax	225	43.8	9,835
9	Carbon Tax	576	43.8	25,222
10	Income Tax	(2)	15.2	(30)
11	**Total Expense**	**$ 6,628**	**38.1**	**$ 252,596**
12				
13	Adjustment for Revised Rates			
14	Income Tax Expense	63	15.2	958
15	**Total Expense at Revised Rates**	**$ 6,691**	**37.9**	**$ 253,554**

Schedule 18.4 – Other Working Capital

Line No.	Particulars	2007 Actual	2008 Decision	2008 Projected	2009 Forecast
1	Pipe	$ 10	$ 12	$ 2	$ 2
2	Fittings	$ 5	$ 4	$ 1	$ 1
3	Regulators	$ -	$ -	$ -	$ -
4	Supplies & Other	$ 2	$ 2	$ 0	$ 0
5					
6	**Total Other Working Capital**	**$ 17**	**$ 18**	**$ 4**	**$ 3**

Schedule 19.1 – 2007 (Actual) Long Term Debt

	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
2007 Actual										
Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ (855)	$ 58,088	12.054%	$ 58,943	$ 7,105	
Series B Purchase Money Mortgage	30-Nov-1991	30-Sep-2015	10.300%	157,274	(2,228)	155,046	10.461%	157,274	16,452	
2004 Long Term Note - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	(1,915)	148,085	6.598%	150,000	9,897	
2005 Long Term Note - Series 19	25-Feb-2005	26-Feb-2035	5.900%	150,000	(1,663)	148,337	5.980%	150,000	8,970	
2005 Long Term Debt Issue - Coastal Facilities	1-Jan-2005	1-Jan-2008	6.100%	50,300	(82)	50,218	6.160%	50,300	3,098	
2005 Medium Term Note - Series 20	24-Oct-2005	24-Oct-2007	4.133%	150,000	(568)	149,432	4.515%	122,055	5,510	
2006 Medium Term Note - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	(784)	119,216	5.595%	120,000	6,714	
2007 Medium Term Note- Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	(2,232)	247,768	6.065%	62,329	3,780	
Medium Term Note - Series 9	21-Oct-1997	2-Jun-2008	6.200%	55,000	(454)	54,546	6.308%	55,000	3,469	
Medium Term Note - Series 9 (Re-opened)	19-Nov-1998	2-Jun-2008	6.200%	58,000	(681)	57,319	6.036%	58,000	3,501	
Medium Term Note - Series 9 (Re-opened)	21-Sep-1999	2-Jun-2008	6.200%	75,000	(2,053)	72,947	6.578%	75,000	4,933	
Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	(2,290)	147,710	7.073%	150,000	10,610	
Medium Term Note - Series 13	16-Oct-2000	16-Oct-2007	6.500%	100,000	(728)	99,272	6.619%	78,904	5,222	
LILO Obligations - Kelowna							6.007%	27,238	1,636	
LILO Obligations - Kelowna Addition							5.205%	2,515	131	
LILO Obligations - Nelson							7.019%	4,704	330	
LILO Obligations - Vernon							8.029%	14,124	1,134	
LILO Obligations - Prince George							7.017%	36,028	2,528	
LILO Obligations - Creston							6.283%	3,405	214	
Debentures Series E	8-Jun-1989	8-Jun-2009	10.750%	59,890	(637)	59,253	10.927%	59,890	6,544	
2007 Adjustment to Forecast								37,178	1,583	
Subtotal								**1,472,886**	**103,362**	
Less: Fort Nelson Service Area Portion of L/T Debt								(2,603)	(192)	7.373%
Mid-Year Long Term Debt								**$ 1,470,283**	**$ 103,171**	**7.017%**

Schedule 19.2 – 2008 (Decision) Long Term Debt

Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
2008 Decision										
Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ (855)	$ 58,088	12.054%	$ 58,943	$ 7,105	
Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	(2,228)	155,046	10.461%	157,274	16,452	
2004 Medium Term Note - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	(1,915)	148,085	6.598%	150,000	9,897	
2005 Medium Term Note - Series 19	25-Feb-2005	26-Feb-2035	5.900%	150,000	(1,663)	148,337	5.980%	150,000	8,970	
2005 Long Term Debt Issue - Coastal Facilities	1-Jan-2005	1-Jan-2008	6.100%	50,300	(82)	50,218	6.160%		-	
2006 Long Term Note - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	(669)	119,331	5.589%	120,000	6,707	
Medium Term Note - Series 9	21-Oct-1997	2-Jun-2008	6.200%	55,000	(454)	54,546	6.308%	22,992	1,450	
Medium Term Note - Series 9 (Re-opened)	19-Nov-1998	2-Jun-2008	6.200%	58,000	681	58,681	6.036%	24,246	1,463	
Medium Term Note - Series 9 (Re-opened)	21-Sep-1999	2-Jun-2008	6.200%	75,000	(2,053)	72,947	6.578%	31,352	2,062	
Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	(2,290)	147,710	7.073%	150,000	10,610	
2007 Medium Term Debt Issue - Series 22	2-Oct-2007	3-Oct-2037	6.000%	250,000	(2,148)	247,852	6.062%	250,000	15,155	
2008 Medium Term Debt Issue - Series 23	1-Jun-2008	1-Jun-2038	5.950%	200,000	(2,000)	198,000	6.022%	116,940	7,042	
LILO Obligations - Kelowna							5.953%	28,747	1,711	
LILO Obligations - Nelson							7.093%	4,555	323	
LILO Obligations - Vernon							8.108%	13,660	1,108	
LILO Obligations - Prince George							7.089%	34,914	2,475	
LILO Obligations - Creston							6.348%	3,303	210	
Debentures Series E	8-Jun-1989	7-Jun-2009	10.750%	59,890	(637)	59,253	10.927%	59,890	6,544	
Subtotal								**1,376,816**	**99,285**	
Less: Fort Nelson Service Area Portion of L/T Debt								(2,935)	(212)	7.223%
Mid-Year Long Term Debt								**$ 1,373,881**	**$ 99,073**	**7.211%**

Schedule 19.3 – 2008 (Projected) Long Term Debt

	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
2008 Projected										
Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ (855)	$ 58,088	12.054%	$ 58,943	$ 7,105	
Series B Purchase Money Mortgage	30-Nov-1991	30-Sep-2015	10.300%	157,274	(2,228)	155,046	10.461%	157,274	16,452	
2004 Long Term Note - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	(1,915)	148,085	6.598%	150,000	9,897	
2005 Long Term Note - Series 19	25-Feb-2005	26-Feb-2035	5.900%	150,000	(1,663)	148,337	5.980%	150,000	8,970	
2005 Long Term Debt Issue - Coastal Facilities	1-Jan-2005	1-Jan-2008	6.100%	50,300	(82)	50,218	6.160%	-	-	
2005 Medium Term Note - Series 20	24-Oct-2005	24-Oct-2007	4.133%	150,000	(568)	149,432	4.515%	-	-	
2006 Medium Term Note - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	(784)	119,216	5.589%	120,000	6,707	
2007 Medium Term Note- Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	(2,232)	247,768	6.062%	250,000	15,155	
2008 Medium Term Note- Series 23	13-May-2008	13-May-2038	5.800%	250,000	(2,060)	247,940	6.022%	116,940	7,042	
Medium Term Note - Series 9	21-Oct-1997	2-Jun-2008	6.200%	55,000	(454)	54,546	6.308%	22,992	1,450	
Medium Term Note - Series 9 (Re-opened)	19-Nov-1998	2-Jun-2008	6.200%	58,000	(681)	57,319	6.036%	24,246	1,463	
Medium Term Note - Series 9 (Re-opened)	21-Sep-1999	2-Jun-2008	6.200%	75,000	(2,053)	72,947	6.578%	31,352	2,062	
Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	(2,290)	147,710	7.073%	150,000	10,610	
Medium Term Note - Series 13	16-Oct-2000	16-Oct-2007	6.500%	100,000	(728)	99,272	6.619%	-	-	
LILO Obligations - Kelowna							5.953%	28,747	1,711	
LILO Obligations - Nelson							7.093%	4,555	323	
LILO Obligations - Vernon							8.108%	13,660	1,108	
LILO Obligations - Prince George							7.089%	34,914	2,475	
LILO Obligations - Creston							6.348%	3,303	210	
Debentures Series E	8-Jun-1989	8-Jun-2009	10.750%	59,890	(637)	59,253	10.927%	59,890	6,544	
Subtotal								**1,376,816**	**99,285**	
Less: Fort Nelson Service Area Portion of L/T Debt								(2,935)	(212)	7.223%
Mid-Year Long Term Debt								**$ 1,373,881**	**$ 99,073**	**7.211%**

Schedule 19.4 – 2009 Long Term Debt

	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
2009 Forecast										
Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ (855)	$ 58,088	12.054%	$ 58,943	$ 7,105	
Series B Purchase Money Mortgage	30-Nov-1991	30-Sep-2015	10.300%	157,274	(2,228)	155,046	10.461%	157,274	16,452	
2004 Long Term Note - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	(1,915)	148,085	6.598%	150,000	9,897	
2005 Long Term Note - Series 19	25-Feb-2005	26-Feb-2035	5.900%	150,000	(1,663)	148,337	5.980%	150,000	8,970	
2005 Long Term Debt Issue - Coastal Facilities	1-Jan-2005	1-Jan-2008	6.100%	50,300	(82)	50,218	6.160%	-	-	
2005 Medium Term Note - Series 20	24-Oct-2005	24-Oct-2007	4.133%	150,000	(568)	149,432	4.515%	-	-	
2006 Medium Term Note - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	(784)	119,216	5.595%	120,000	6,714	
2007 Medium Term Note- Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	(2,232)	247,768	6.065%	250,000	15,163	
2008 Medium Term Note- Series 23	13-May-2008	13-May-2038	5.800%	250,000	(2,060)	247,940	5.884%	250,000	14,710	
2009 Medium Term Note- Series 24 (replace series E)	8-Jun-2009	8-Jun-2039	6.000%	150,000	(568)	149,432	6.090%	65,342	3,979	
Medium Term Note - Series 9	21-Oct-1997	2-Jun-2008	6.200%	55,000	(454)	54,546	6.308%	-	-	
Medium Term Note - Series 9 (Re-opened)	19-Nov-1998	2-Jun-2008	6.200%	58,000	(681)	57,319	6.036%	-	-	
Medium Term Note - Series 9 (Re-opened)	21-Sep-1999	2-Jun-2008	6.200%	75,000	(2,053)	72,947	6.578%	-	-	
Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	(2,290)	147,710	7.073%	150,000	10,610	
Medium Term Note - Series 13	16-Oct-2000	16-Oct-2007	6.500%	100,000	(728)	99,272	6.619%	-	-	
LILO Obligations - Kelowna							5.953%	27,238	1,621	
LILO Obligations - Nelson							7.093%	4,704	334	
LILO Obligations - Vernon							8.108%	14,124	1,145	
LILO Obligations - Prince George							7.089%	36,028	2,554	
LILO Obligations - Creston							6.348%	3,405	216	
Debentures Series E	8-Jun-1989	8-Jun-2009	10.750%	59,890	(637)	59,253	10.927%	25,925	2,833	
Subtotal								**1,462,983**	**102,303**	
Less: Fort Nelson Service Area Portion of L/T Debt								(3,119)	(225)	7.223%
Mid-Year Long Term Debt								**$ 1,459,865**	**$ 102,078**	**6.992%**

SECTION 11 – GLOSSARY OF TERMS

Commission

- British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia. Also known as the BCUC.

GCRA – Gas Cost Reconciliation Accounts

- A deferral account used to record variances between the TG Fort Nelson forecast and actual gas purchase costs. GCRA balances are either recovered through rates or refunded to customers in subsequent years through the GCRA rider.

GJ – Gigajoule

- A measure of energy of natural gas equal to one billion joules, used for billing purposes. One gigajoule (GJ) is equivalent to approximately 278 kilowatt hours of electricity or 28.85 litres of gasoline.

PBR – Performance Based Ratemaking

- A process for determining delivery charges and incentive mechanisms for improved operating efficiencies.

Revenue Requirement

- The total amount of money a utility must collect from customers to pay all operating and capital costs, including a fair return on investment.

Rider

- A temporary adjustment to rates usually reflecting the disposition of deferral account balances.

RSAM

- Rate Stabilization Adjustment Mechanism (RSAM) is a deferral account used to record variances between forecast and actual core market and industrial margins resulting from changes in use per customer from factors such as colder or warmer than normal temperature. RSAM balances are either recovered through rates or refunded to customers in subsequent years through the RSAM rider.

TJ – Terajoule

- One million million joules (10^{12}).

Transportation Service

- Gas delivery service provided by Terasen Gas to customers who purchase natural gas directly from producers or marketers (customers served under Rate Schedule 25 within TG Fort Nelson).